

CALIFORNIA ENERGY COMMISSION

FUELS

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GRAY DAVIS, GOVERNOR

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COMMITTEE REPORT

CALIFORNIA ENERGY COMMISSION

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EXECUTIVE SUMMARY

Fuel is critical to California's economy. Consumer expenditures on fuel alone amount to \$34 billion each year in California. But the contribution goes well beyond consumer expenses on the fuel itself. These fuels enable countless transactions in the marketplace each day between buyers and sellers of goods and services. The delivery of nearly every product sold in the marketplace depends on fuel, greatly magnifying its total contribution to our economy and lifestyle. The *Fuels Report* is unique in that it describes, under one cover, California's emerging fuel trends and future fuel price and supply expectations. Furthermore, it is the state's primary fuels policy document.

WORLD OIL MARKET AND PRICE TRENDS

World oil demand has been growing at roughly 1.5 percent per year since 1986 and now amounts to about 74 million barrels per day. Demand growth in developing countries has been more pronounced at 5 percent per year. China's oil demand alone has been growing at an annual rate of almost 8 percent since 1992. During 1998, however, the rate of Asian oil demand fell off dramatically largely due to their economic downturn, although demand in the US and Europe steadily increased. Extrapolating these trends to the future is risky since small changes in the factors affecting oil demand growth can have cumulatively large impacts over time. Taken as a whole, though, the overall steady nature of demand growth may itself be a source of stability in oil markets in that it provides the petroleum industry a clear incentive to invest in exploration and development.

Despite ample current US oil inventories, in a global market no region is immune to the effects of supply disruptions from oil exporting nations. Political struggles and wars have been persistent features of the oil price shocks experienced during the last few decades. The world oil market, however, has adapted somewhat over time to this vulnerability as seen by the results of the Iraqi invasion of Kuwait in 1990. Over four million barrels per day of oil export capacity were lost overnight, without leading to a prolonged period of higher prices.

Even though the Organization of Petroleum Exporting Countries' (OPEC) influence of the late 1970s and early 1980s is not expected to return, OPEC still maintains world oil prices above their competitive levels by carrying unused oil production capacity. While consumers in oil importing countries sense an understandable vulnerability to sudden supply disruptions, they should remember that oil exporters need oil buyers over the long-term. Oil exporting countries can hedge their economic position by finding friendly havens for investment, entering into exploration and development joint ventures at home, and launching refining, distribution, and sales joint ventures in foreign markets. Many oil exporting countries have recognized the necessity of privatizing national energy industries and liberalizing trade and investment rules, easing taxation and regulations, and/or obtaining outside expertise and capital.

World petroleum markets now appear to be in a period of balance between the extremes of previous decades, without the consistently low crude oil prices and unfettered petroleum demand growth of the pre-OPEC cartel period, but also without the political and economic instability of the period of OPEC official pricing. Most credible long-term world oil

price forecasts indicate still lower world oil prices, with flatter growth rates. This change does not mean that price volatility vanishes. In fact, rapid short-term price fluctuations in response to changing market conditions may be essential to a sustainable and open world oil market.

The Commission staff has proposed high, mid and world oil price forecasts. The high and mid-case forecasts are flat in inflation-adjusted terms. The low price forecast shows a decline in prices. The high price forecast is about \$21 per barrel. The mid-price forecast is about \$19 per barrel. The low price case declines from \$19 per barrel to \$16 per barrel. All prices are in inflation-adjusted 1998 dollars.

Integral to these forecasts are assumptions of significant price variation around both annual and daily averages of as much as \$5 per barrel. In the short-term, prices can and do vary significantly because they are affected by many factors. When oil prices increase consumers pay higher fuel prices; these higher prices can adversely affect the economy.

OIL SUPPLY OUTLOOK FOR CALIFORNIA

From a broad perspective, the oil supply outlook for California remains one of declining in-state and Alaska supplies leading to increasing dependence on foreign oil sources. The estimates of when foreign sources will predominate the California market, however, have been lengthened by five years compared to the previous *Fuels Report*. The time extension relates to greater volumes of Alaska oil production than previously expected. In addition, recent statistics indicate that although California production continues to decline, it is at a lower rate (0.8 percent per year) than the 1985 to 1990 average rate (4 percent per year).

In the short-term, California may see annual production declines greater than 0.8 percent given the current weak price environment for California's heavy crude oil with prices below \$10 per barrel. Production in 1998, for example, declined 3 percent from the previous year. While most of the decline occurred in federal offshore fields, onshore production declined as California heavy crude oil prices dropped to \$7 per barrel during the last quarter of the year.

In the long-term, the staff expects continuing, gradual California production declines as world oil prices remain flat, but at slightly lower rates than presented in the *1995 Fuels Report*. Several factors support this expectation.

Royalty rates have been reduced on California heavy crude oil production from federal leases. The construction of a new oil pipeline is also now complete, increasing the capacity to transport more in-state oil from Bakersfield to refineries in Los Angeles. Furthermore, a West Coast technology information center now offers information to many small producers, to help extend the life of marginal oil wells.

The staff's revised estimate of when foreign oil imports are expected to exceed California's supply from Alaska is 2006. The estimate for foreign oil to exceed in-state supply is 2012. Furthermore, the estimate of when foreign oil supplies could exceed the halfway mark in California's total oil supply picture is 2016.

Short-term oil supply trends often differ greatly from long-term trends. In recent years, California onshore production has increased because of higher overall oil prices. More recent data (since March 1998), however, reveals that California heavy crude oil prices have fallen dramatically, at times to less than \$7 per barrel. These price conditions negatively affect production, as well as employment and tax collections -- features that lose visibility in long-term forecasts which "smooth out" short-term conditions. Small independent producers who rely solely on exploration and production earnings for their livelihood are facing financial difficulties. As a result, independent producers are calling for government action to help preserve this industry group.

While oil price was not explicitly incorporated into the supply forecasts, the outlook for world prices in the long-term does not offer reassurance that domestic production will reverse itself on a sustainable basis. Greater foreign oil dependence, however, does not necessarily mean higher prices and may mean lower prices. Supporting evidence can be found in the world oil price forecast which reflects a long-term future of stable, if not declining, international oil prices. As dependence on foreign oil increases, California can expect to see a variety of ready suppliers. South America and Middle East crude oil suppliers are likely candidates. Californians can also expect to see an increase in marine tanker traffic as foreign imports increase.

The Commission should continue to evaluate the economic, environmental and energy policy implications of oil import growth and potential crude oil and product transportation and storage constraints.

PETROLEUM FUEL PRICES AND VOLATILITY

Petroleum Fuel Price Forecast

The Commission staff prepared low, mid and high price forecasts for six fuel types including: California Air Resources Board (CARB) Phase 2 reformulated gasoline, CARB-specification reformulated number 2 highway diesel, railroad diesel, agricultural diesel, commercial kerosene jet fuel and fleet propane. Long-term price ranges are:

- CARB gasoline, \$1.08 to \$1.37 per gallon
- CARB diesel, \$1.03 to \$1.45 per gallon
- railroad and agricultural diesel, from \$0.67 and \$0.72 per gallon, respectively, to \$0.88 to \$0.91 per gallon
- commercial kerosene jet fuel, from \$0.62 to \$0.86 per gallon
- fleet propane, from \$0.63 to \$1.02 per gallon

Petroleum Product Price Volatility

Volatility in product prices around the above long-term prices occurs as a result of many factors, including:

- oil price variations
- refinery maintenance and unplanned outages
- seasonal and annual demand fluctuations

- changes in markup and taxation of products
- Estimates of the impact of oil price volatility alone on product prices are included in the Commission's forecast for the first time. The staff's analysis indicates that gasoline prices could vary by five to eight cents per gallon higher or lower than projected due to normal variation of oil prices around long-term forecasts. Diesel fuel prices could vary by 13 to 20 cents per gallon higher or lower than projected, jet fuel by 15 to 24 cents per gallon, and propane by 23 to 35 cents per gallon as a result of oil price variation. The effects of factors other than oil prices are most pronounced with CARB Phase 2 gasoline.

Petroleum Fuel Reserve

Over the last two years, gasoline and diesel price fluctuations created renewed interest in establishing a California petroleum fuel reserve. A physical reserve of products can be seen as one means of providing price stability in the marketplace. The staff analyzed the economic feasibility of using the large, unused residual fuel oil storage facilities at electric utilities as a price-dampening gasoline and diesel fuel reserve.

The staff concludes that a product reserve would be marginally economic at best. This conclusion is based on a 20 year reserve life, the costs of converting existing storage tanks, the cost of initial inventory purchases and of ongoing storage costs. If during restocking, prices increase by more than two cents per gallon, the reserve would become uneconomic. One factor not incorporated into the analysis, but that could further negate the benefits of a reserve, is refiner behavior. With a large California product reserve, refiners might lower their own inventories and offset the positive effects of a reserve.

Paper Markets

Paper markets are another option for reducing possible financial risk associated with future energy prices. Existing paper, or financial, instruments such as futures and options contracts reduce uncertainty by specifying the price, quantity and the date of future energy deliveries. Since a physical reserve was found to be of questionable value, the staff investigated paper markets as an alternative means of dealing with price volatility. Generally,

paper markets allow individuals and firms to transfer their exposure to price fluctuations to traders willing to accept this risk with expected compensation. Since traders hedge adverse price movements in both directions, financial instruments tend to stabilize prices. Financial instruments specifically designed for California's unique petroleum product market would provide refiners and consumers with more risk management tools.

PETROLEUM PRODUCT ISSUES

The staff investigated several petroleum product issues including fuel excise taxation, the cost and availability of alternative fuels and vehicles, the potential for market power in the petroleum industry, and the price and supply effects of discontinuing MTBE in California gasoline.

Fuel Excise Taxation

The fuel excise tax issue centers around developing a means to balance the need for transportation-related revenues with sound energy policy and equitable fuel tax treatment. Both federal and state excise taxes are applied to most transportation fuels, but disparities in the amount of the tax and the disconnection from energy policy considerations at both the federal and state level have posed contentious public debates.

The Commission staff compared tax rates using three means of expressing current federal and state excise taxes. These included taxes expressed currently in cents per gallon, taxes based on a dollar-per-million-Btu measure given certain assumptions on fuel Btu content, and taxes on a cents-per-mile basis given assumptions on vehicle fuel economy and fuel substitution factors, or the amount of another fuel required to replace one gallon of gasoline.

These comparisons not only illustrate the disparity, but they also show that the tax ranking for various fuels changes, depending on the method of comparison used. Federal and state tax exemption provisions further complicate comparisons and influence the economics of fuel choices in some user categories, such as state and federal government

fleets and school districts. The staff concludes that there is a need for a uniform, accepted basis for assessing excise taxes on all forms of transportation energy that is technically sound, fiscally responsible, and supportive of rational energy goals.

The Commission should take an active role in bringing greater uniformity to federal, and especially state, excise tax determinations by undertaking the necessary technical analyses to develop an appropriate method of assessment and preparing consequent legislative proposals for excise tax revisions.

Cost and Availability of Alternative Fuels and Vehicles

Legislation directs the Commission to conduct continuing studies on the cost and availability of alternative motor fuels, including cost comparisons of owning and operating alternative fuel vehicles (AFVs) versus gasoline vehicles. The staff's updated analysis, using actual costs of AFV models available in California, shows that total AFV costs continue to be higher than gasoline counterparts. Depending on the vehicle model, fuel type, and purchase option -- differences range from 0.4 cents per mile for the Ford Super Club Wagon to over 23 cents per mile for the Ford Ranger electric pickup truck.

For methanol, both higher fuel and vehicle costs contribute to the difference. Compressed natural gas, liquefied petroleum gas and electricity cost less than the energy equivalent of gasoline, but higher vehicle prices override this fuel cost component. The result is that compressed natural gas vehicle operation costs about 0.5 to 6 cents more per mile than gasoline counterparts. Similar results were found with liquefied petroleum gas vehicles, which cost about 1.5 to 7 cents per gallon more than gasoline models.

The disparity between gasoline and electric vehicle operation and ownership costs is greater still with differences ranging from 13 to 23 more cents per mile to lease and operate an electric vehicle versus owning and operating a similar gasoline vehicle. Despite these findings, AFV use may increase further as regulations increasingly restrict emissions. Today, the limited slate of original equipment manufacturer AFV models and cost considerations restrict greater consumer use.

Retail Station Divestiture

Gasoline prices are higher in some localities than others. The price difference can be related to many factors including local competition, customer conveniences provided, station sales volumes and location, brand loyalty, etc. Because of gasoline price differences between and within regions of California, some independent retailers and consumers are calling for divestiture of the wholesale sales function from the retail function for vertically integrated oil companies.

It is argued that this separation would increase competition in the market and lead to more uniform or equitable gasoline pricing. The Commission is not aware of any studies concluding that these market changes would produce the desired result, but the concern over gasoline price variations identifies the need to more fully inform the public of factors that influence gasoline prices.

The Commission should methodically evaluate factors other than oil prices that contribute to regional retail gasoline price differences and publish the results to better inform the public about the causes for price differences.

Market Power

Market power refers to the ability of companies to maintain prices above competitive levels for a significant period of time. Mergers and joint ventures among large companies, in any industry, raise the concern of the possible exercising of market power by the restructured firms. The question emerging from the abundance of consolidations in the petroleum production, refining and marketing industry is whether these activities result in increased market power being exercised.

The Commission staff analyzed the market power issue relating to the refining and marketing segments of the California petroleum industry. Using four different cases with differing assumptions on specific company merger activity, the staff estimated market share of the four largest firms and calculated the Herfindahl-Hirschman Index (HHI) numbers which indicate relative market concentration. The five parameters studied include

product refining capacity, retail gasoline sales, gasoline production, wholesale gasoline sales and diesel production.

Company consolidations increase both the market share of the four largest firms and the HHI for California. The four largest firm measure produced numbers well above the 60 percent threshold value established by industry analysts. The post-merger HHI numbers suggest a moderately concentrated market according to the federal guidelines for mergers. The increase of the post merger HHIs indicates that the consolidation can enhance market power. Only a more rigorous analysis, however, that considers additional factors can confirm or disprove this notion.

The Commission should conduct a more rigorous market power analysis of gasoline production and sales to confirm or disprove that existing merger activity enhances market power.

Underground Fuel Storage Tanks

As of December 22, 1998, underground petroleum product storage tanks must have been replaced or upgraded to meet federal and state standards for leak prevention and monitoring. In California, the concern was that station owners in more remote rural areas of the state would not complete the improvements and result in facility closures. The closures would then cause important public services – such as fire, emergency, school and other services – from accessing refueling facilities.

The Commission staff assessed the available compliance data and found that most existing stations in rural areas have remained in business since additional financing for tank replacements is now available and some owners chose to install above-ground tanks. Some remote areas permanently losing refueling facilities, however, remains a strong possibility for stations that have been only marginally viable in recent years. The Commission will continue to monitor these trends to identify where serious fuel availability problems may arise and make necessary recommendations.

MTBE and Fuel Supply and Price

The Energy Commission, at the request of the Legislature and the Governor, examined the potential supply and price effects of discontinuing Methyl Tertiary Butyl Ether (MTBE) in gasoline. This undertaking included analyzing California's refinery infrastructure, researching the availability and price of alternative oxygenates, and determining product import capabilities and distribution system limitations. The work considered four alternative oxygenates and entailed constructing several cases to model California's gasoline supply and price response, under three time horizons, to differing economic and regulatory conditions.

The cost impact to consumers is reduced as the time permitted to accomplish a potential transition to other, or reduced, oxygenate use is increased. If MTBE is discontinued with no phase-out time permitted, gasoline supplies could decline 15 to 40 percent, with retail price increases of 30 cents and more per gallon, regardless of the oxygenate option chosen. This option would significantly damage consumer lifestyles and the state's economy. Under a three year phase-out plan, the gasoline production cost change ranges from a decrease of 0.2 cents per gallon to an increase of nearly 9 cents per gallon. With a six year phase-out, the average production cost ranges from a 0.3 cent per gallon decrease to a 3.7 cent per gallon increase.

Average changes in cost do not represent retail gasoline price changes, which may be higher still, because factors other than production cost influence pump prices. The Commission staff report, *Supply and Cost of Alternatives to MTBE in Gasoline*, October 1998 discusses study results and key findings in more detail.

Based on the results of the Commission's study, an in depth University of California study on the water quality impacts of MTBE, and public testimony received in several hearings, Governor Davis signed an executive order on March 25, 1999, to remove MTBE from gasoline at the earliest possible date, but not later than December 31, 2002. The Commission is directed to develop, in consultation with the California Air Resources Board, a timetable for removing MTBE from gasoline. In addition, the Commission is directed to evaluate the potential for developing a waste-based or other biomass ethanol industry in California.

The Commission will fulfill the directives in the Governor's executive order relating to the

timetable for phasing out MTBE in gasoline and evaluating the potential for developing a waste-based or other biomass ethanol industry in California.

Transportation Fuel Demand

The Commission staff prepared transportation fuel demand forecasts for gasoline, diesel, compressed natural gas and electricity. The base case gasoline forecast indicates that demand could increase from 0.5 to 1.2 percent per year, resulting in 14.4 to 16.3 billion gallons of fuel use per year by 2015.

Differing assumptions on improvements in new light-duty vehicle fuel efficiency and the influence of alternative fueled vehicles account for the variation. Diesel fuel demand is forecast to increase at 1.5 percent per year to 3.3 billion gallons per year by 2015. Compressed natural gas transportation demand increases from 0 to 10 percent per year in the high and low gasoline demand scenario, respectively. Electricity use increases from 2 to 14 percent per year in the forecast.

The staff also extrapolated historical sales trends for sport utility vehicles to estimate future gasoline demand. Approximately 1.4 million more sport utility vehicles would be on the road by 2015 with a resulting 0.4 billion gallon, or 2.5 percent, increase in gasoline demand over the base case high demand scenario.

NATURAL GAS SUPPLY, DEMAND AND PRICE

Regulatory reforms over the past two decades have changed the way natural gas markets function. More options are available to many end users in today's progressively competitive market. Two regulatory proceedings now underway will continue to affect the direction of the gas industry during the coming decade.

At the state level, the California Public Utilities Commission instituted a rulemaking proceeding in January 1998 designed to provide residential and commercial customers with the competitive choices currently available to large industrial and power

generation customers. At the national level, the Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking in July 1998 to eliminate cost-based regulation for gas transportation services of less than one year. The intent is to reduce the number of captive customers and provide greater flexibility to allow pipeline companies to redesign services to better meet customer needs. Since both proceedings are in the early stages of investigation, the Commission does not expect new natural gas rules to be adopted for at least two years. A wide range of issues must be addressed before any action is taken by either agency.

Natural gas supplies to California will remain plentiful for the next several decades. The total resource base (gas recoverable with today's technology) for the lower 48 states is estimated to be about 975 trillion cubic feet (TFC), enough to continue current production levels for more than 50 years. Technology enhancements will continue to enlarge the resource base, however, production capacity increases remain less certain. Despite this concern, production from lower 48 states is expected to increase from 17.1 TCF in the 1994 base year to 25.9 TCF in 2019. The Gulf Coast and Rocky Mountain supply regions account for most of the increase during the next two decades. Alberta continues to provide the bulk of Canadian production. Canadian exports to the United States are projected to rise to 3.9 TCF in 2014 and remain at that level thereafter.

In 1997, Californians consumed 5.5 billion cubic feet (BCF) of natural gas per day, the highest level reached since the drought of 1994. Approximately one-third of this consumption was for electricity generation, a leading growth market in California. Residential consumption represented one-fourth of California natural gas use with the balance consumed by the industrial, resource extraction and commercial sectors. The Commission's gas demand forecast is for continued growth at 1.3 percent per year, exceeding 7 BCF by 2019.

The average wellhead price in the lower 48 states is expected to increase from \$1.65 per thousand cubic feet (MCF) in 1999 to \$2.18 per MCF in 2019, representing an annual average increase of 1.4 percent. In Canada, the average price is projected to increase 2 percent per year in real terms from \$1.17 per MCF in 1999 to \$1.75 per MCF by the year 2019. The expected growth rate in wellhead prices is considerably lower than previous Commission

estimates, which have consistently been in the range of 3 to 4 percent. A major factor contributing to this lower growth rate is due to the incorporation of reserve appreciation.

Natural Gas Supplies and Prices at the California Border

Four producing regions supply California with natural gas. Three of them -- the Southwest US, the Rocky Mountains and Canada -- provide approximately 85 percent of all gas used in the state. The remainder is produced inside California. The total supply to meet California consumption is expected to increase from 5.9 BCF per day in the 1994 base year to 7.8 BCF per day by 2019.

No significant changes are anticipated in the market shares of supplies from these four supply regions over the forecast horizon. Southwest supplies will continue to dominate, holding approximately half of the market. Canadian producers will supply another quarter of the market with the remainder split between Rocky Mountain and California suppliers. The average California border price is expected to increase by 1.9 percent per year from \$1.79 per MCF in 1999 to \$2.62 per MCF in the year 2019.

California End-Use Natural Gas Price Forecast

The analysis indicates that natural gas prices to generate electricity in the PG&E and SoCal Gas service areas will be very competitive. Because of additional costs to transport natural gas through the SoCal Gas service area, SDG&E natural gas prices for electric generation are about 30 cents higher than that in the SoCal Gas service area. This trend will continue as long as the current pricing structure is maintained. The merger of SDG&E and SoCal Gas and separation of gas utility services could change this situation.

Need for Additional Interstate Pipeline Capacity to California

Despite the fact that excess interstate pipeline capacity now exists, additional pipeline capacity is

expected to be needed at the California border during the next two decades. The Commission estimates a need for additional delivery capacity from the Rocky Mountains in 2004 and Canada in 2009. Additional delivery capacity at Wheeler Ridge, located south of Bakersfield, will also be needed by 2009 to accommodate additional flows from these regions. No additional delivery capacity will be needed from the Southwest; however, the expansion of the pipelines moving San Juan Basin gas, in the Four Corners area, to California will be needed by 2004. Additional capacity will be needed on the SoCal Gas system at Topock by 2009 to receive increasing supplies from the Southwest. Topock is located at the California/ Arizona border near Needles, California.

Market Fundamentals

Although the forecast is based on a “most likely” perspective of market expectations, many uncertainties surround the competitive natural gas marketplace. To address this critical issue, several cases were created to test the bounds of supply, demand and price over the forecasted horizon.

These cases addressed the power generation market, resource availability, technology advances, overall demand and market structural changes. A high price and low price case were also generated to provide a lower and upper bound on the direction of future natural gas prices. The high price case generated wellhead prices that are 50 to 75 cents per MCF higher than the base case over the forecast horizon. In contrast, the low price case produced prices 40 to 60 cents per MCF lower than the base case, depending upon the assumptions made in each case.

Importance of Natural Gas Market Centers

Increasing competition among producers, transporters and distributors has created market centers or “hubs” where natural gas is bought and sold competitively. Market hubs clearly impact the price at which natural gas is traded. Producers have the option of selling to high bidders while consumers have the option to go to the lowest price seller. Through electronic bulletin boards and other

mechanisms, market participants are more informed, which enhances competition, putting downward pressure on prices. Transactions occur for various contract periods, such as long-term contracts and spot or daily contracts. It is probable that these market transactions in the future might even occur hourly.

Today, the choices in competitive markets are available mainly to large gas consumers such as industrial customers and, to some extent, smaller customers through core aggregators or marketers. The number of players will increase as small and large consumers gain better access to competitive service options envisioned in the restructured natural gas market.

SYNTHETIC PETROLEUM FUEL AND FUEL CELL PROSPECTS

Synthetic Diesel Fuel

Some companies are using a gas-to-liquid process to convert remote natural gas resources into synthetic petroleum products, such as diesel fuel. The fuel produces exhaust emissions that are 5 to 40 percent lower than those from conventional diesel fuel, and technology improvements are reducing conversion costs. When blended with conventional diesel fuel, the resulting mix can meet CARB stringent diesel fuel standards.

While no facilities for producing the fuel exist in California, synthetic diesel was used to a limited extent in 1997 as a feedstock in California refineries. Several conversion plants are operating or under construction worldwide, and California refiners may show greater interest in obtaining synthetic diesel fuel as an option for increasing clean diesel fuel production without costly refinery modifications. Cost reductions in the conversion technology may also result in many smaller gas fields being developed in the future. While difficult to quantify the volume of worldwide production that may make an inroad to California, the qualities of the fuel, strict diesel fuel standards and its initial use in the state suggest that a market may be found here.

The Commission should continue to monitor worldwide research, development, demonstration and commercialization efforts associated with synthetic diesel fuel for possible application and use in California.

Fuel Cell Vehicles

While one manufacturer has announced plans to produce fuel cell vehicles (FCVs) within six years, the widespread use of FCVs will require a well developed fueling infrastructure for fuels other than gasoline. Even the significant infrastructure advantages of gasoline, however, are accompanied by questions on gasoline sulfur content which presently poisons the catalyst used in fuel cell technology. Gasoline-fueled FCVs would likely require the use of a new formulation that would then need to be kept separate from conventional gasoline supplies.

Despite the current absence of a hydrogen or methanol fueling infrastructure, a survey of knowledgeable individuals indicated that these two fuels are expected to be the preferred fuels in the coming years for use in FCVs. Hydrogen and methanol producers expect that they could meet fuel demand if FCVs came into widespread use, but many

retail level issues remain. In the case of hydrogen, adequate storage on board vehicles and fuel cost are primary issues. Hydrogen fueling infrastructure also requires large capital investments compared to traditional fuels. Estimates for a complete system are in the hundreds of billions of dollars.

California's experience with methanol as a vehicle fuel would benefit efforts to commercialize methanol use in FCVs; however, caution must be exercised in ensuring that existing storage tanks, piping and other components used in a gasoline fuel station are methanol compatible. Vehicle purchasers must also see clear and significant benefits if they are to choose non-conventional fuels such as methanol. Because providing FCV infrastructure requires time, planning today for potential future needs is prudent. If manufacturer plans materialize, FCVs may begin displacing some conventionally fueled internal combustion engines with near zero emission vehicles in the future.

The Commission should continue to monitor fuel cell technology progress, infrastructure development and the potential use of FCVs.

Chapter 1

WORLD OIL MARKET TRENDS AND PRICES

WORLD OIL DEMAND

This chapter discusses factors affecting the demand for and supply of crude oil to world energy markets. These factors include economic growth, technology development and government policies. Historical data on crude oil demand and world oil prices are provided. The Commission staff's forecast of world oil prices and potential price variations are also provided.

Crude oil is freely traded, physically and on paper, in an open world market. Once adjustments to oil prices due to oil quality, transportation costs and competitive relationships with other primary fuels have been made, the California energy market will be supplied with the quantity, quality and market share of oil that it demands (i.e. is willing to pay for). Barring major system disruptions due to war or natural catastrophe, sufficient oil of adequate quality will be available to California. Events and trends in many different regions can affect the overall supply and demand balance, however, and therefore also affect the price of oil to the state.

Economic Growth

While economic growth rates have been high in much of Latin America and until recently in the greater Asia region, the prospect of a rapidly industrializing, urbanizing China has some analysts

anticipating unprecedented growth in demand for energy, including oil for transportation use. Since 1983, China has averaged about 10 percent per year real gross domestic product (GDP) growth.¹ It has ambitious plans to increase its GDP at an average rate of 6.5 percent per year for the next 25 years.² If Russia, Eastern Europe, and the Central and South Asian nations also start to realize their economic potential, this circumstance would further augment overall demand. As recent disruptions in Asian and Russian currency and stock markets illustrate, however, financial, environmental and other social problems can accompany and stall rapid economic growth.

Although higher economic growth and increased petroleum use are linked, the relationship is not entirely straightforward. Several factors affect trends in energy use and changing market shares of the different fuels over time. These factors include government policies, competing primary fuel prices, short-term price and income elasticities of demand, and long-term adjustment lags. An important part of the long-term adjustment is capital investment in energy efficient technology, such as insulation, fuel efficient vehicles, cogeneration facilities, or more energy efficient or dual-fuel industrial power plants. Efficiency investments made in response to higher energy prices are often not undone if energy prices later decline. Since many of the easy efficiency fixes have already been made in the industrialized world, however, future efficiency gains there will be more costly.³ At the same time, there will still be a

substantial market in developing countries for well-tested, efficient technology that will stem significant petroleum use in stationary sources.⁴

Policies and Trends

Policies intended to lower oil demand or simply obtain revenues can lead to a divergence of prices for crude oil and products.⁵ Taxes, fees and regulations that add to the cost of petroleum products such as gasoline and diesel in many regions have tended to increase retail prices, often during times of declining oil prices. Industrialized oil-importing countries have sometimes increased these user costs to pay for highways, to improve environmental quality or just to capture some of the revenues that would otherwise go to oil-exporting countries. As these user costs increase in proportion to total fuel prices, they raise the average retail fuel price and dampen demand. This policy approach to reducing petroleum product demand and its social impacts has not set well with the Organization of Petroleum Exporting Countries (OPEC) and has raised concerns that OPEC might attempt to “retaliate.” Raising retail costs of fuels also does not set well with consumers, especially in the US, but also in many other countries that previously controlled end use prices below competitive levels.

World oil demand grew by over 11 million barrels per day (18 percent overall) between 1986-97, roughly 1.5 percent per year, to over 73 million barrels per day in 1997.⁶ From 1992-97, oil demand in the developing countries (those countries outside the former Soviet Union that are not in the Organization of Economic Cooperation and Development) has grown at an average annual rate of over 5 percent. China’s oil demand alone has grown at an annual rate of almost 8 percent since 1992. During 1998, however, the rate of oil demand growth fell off dramatically in China and declined in countries such as Thailand, South Korea and Indonesia because of downturns in their economies. In the meantime, though, demand in the US and Europe has steadily risen, and worldwide demand for petroleum products in 1998 averaged about 74 million barrels per day.

Extrapolating from these trends to the future is not without risk, as small changes in the factors affecting oil demand growth can have cumulatively

large impacts over time. Taken as a whole, though, world

oil demand growth trends appear fairly predictable in direction and, to a lesser extent, in magnitude. That is in large part because significant deviations in oil demand growth soon affect oil prices which in turn affect oil demand. Finally, the steady nature of demand growth may itself be a source of stability in oil markets in that it provides the petroleum industry a clear incentive to continue investing in exploration, even during periods of weak oil prices such as those seen in 1998 and continuing into early 1999.

WORLD OIL SUPPLY

There would be little concern about growth in world demand for crude oil if there was no question about the long-term ability of oil producers to produce and traders to distribute sufficient quantities of oil to meet that need. Many factors on the supply-side do affect the price of oil, however, and in the future they may become even more important. Among these factors are the amount and geographic distribution of oil resources, the actions of OPEC, trends in privatization of national energy industries, the alleviation of trade and investment barriers between countries, the effects of technological innovations and organizational changes on sectors such as the oil industry, and the maintenance of economic sanctions on important petroleum producing countries.

A debate is currently being waged in the energy literature over whether oil resources have been depleted to the point where worldwide production of lower-priced conventional crude oil is about to peak. According to some, this near-term peak is irreversible, and sharp price increases are inevitable, probably before 2005.⁷ These analysts discount the likelihood that large new fields will be found, or that sufficient unconventional oil (bitumen, tar sands and shale deposits) will be available quickly enough to put off this peak. This depletion hypothesis is rejected by other analysts who take the position that the free flow of capital, information and technology across the global resource base guarantees that oil reserves will be added as they are needed.⁸ Other researchers argue that the world is still incompletely explored for conventional oil, or conclude that future reserve growth is routinely underassessed.⁹ Still others are more blunt, claiming that these depletion

forecasts are not new and have been consistently wrong in the past.¹⁰

Supply Disruptions

Even if ample crude oil remains in reserve, however, in a global market, no oil importing region is immune from the effects of supply disruptions from oil exporting nations. Political struggles and wars have been persistent features of the oil price shocks experienced during the last few decades, most noticeably in the Middle East where the bulk of the world's most accessible reserves are found. The case might be made that the world oil market has adapted somewhat over time to this vulnerability.

For instance, the Iraqi invasion of Kuwait in 1990 led to the immediate loss of over four million barrels per day of oil export capacity, and Iraq's exports are still severely limited by UN sanctions. Yet no significant shortages occurred and, after a short price spike, oil prices quickly declined and stayed relatively low for years. This response is in marked contrast to the prolonged impacts of the 1973-74 embargo, 1979 Iranian Revolution and subsequent Iran-Iraq war, when lesser quantities of oil became unavailable to the market.

For all its unsettled history, though, OPEC has indelibly changed the world oil market. Even though the OPEC's influence of the late 1970s and early 1980s is not expected to return, OPEC still maintains world oil prices above their economically "competitive" levels by carrying unused oil production capacity, nearly 5 million barrels per day in 1996, or 16 percent of total production capacity for OPEC as a whole. Saudi Arabia accounts for the largest share.

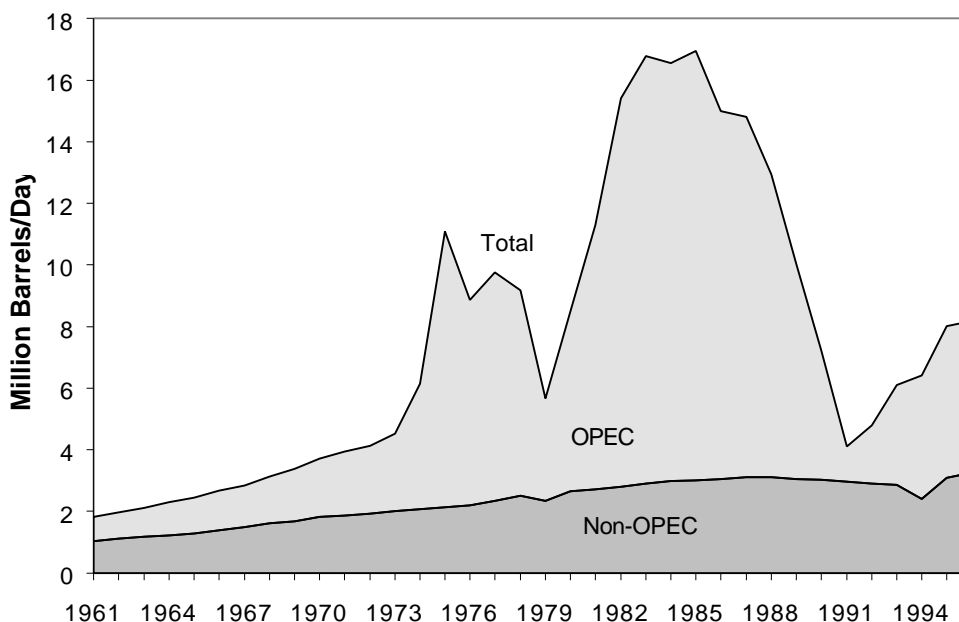
The relationship of excess production capacity to oil prices is complex, however, and depends on whether the capacity is being withheld specifically to raise prices, or because it is unneeded, or (as in the 1991 Gulf War) is used to offset unexpected supply shortfalls drawn down due to unexpected contingencies. Figure 1-1 illustrates how excess production capacity has changed over time for OPEC and non-OPEC countries. Excess world oil production capacity as a percentage of total capacity is expected to remain at or above 1996 levels through at least 2002.¹¹

While oil importing countries feel understandable vulnerability to sudden supply disruptions, the level of dependency of oil exporters on oil consumers is not commonly appreciated. This dependency goes beyond their long-term need for buyers of oil, their major (and sometimes only) source of significant revenues. In a competitive global economy, oil exporters need to "hedge" their economic position by finding friendly havens for investment, entering into exploration and development joint ventures at home, and refining and sales ventures in foreign markets. It also requires competing for foreign capital and technical expertise and obtaining allies for purposes of military security. As the flow of all goods and services become more complex, participating nations become more dependent on each other as they also tend to become more prosperous.

Privatizing national energy industries and liberalizing trade and investment rules have also broken down the perceived separation between oil producers and consumers. Many producing countries -- the United Kingdom, Norway, Argentina, and even Russia -- have recognized the need to break up state energy industries, ease taxation and regulations, and/or obtain outside expertise and capital. Closer to home, the federal stake in the large Elk Hills Naval Petroleum Reserve near Bakersfield, California was recently sold to Occidental Petroleum Corporation for \$3.65 billion, the largest privatization in the history of the US government.

Privatization and liberalization have been unevenly implemented, however, and in some countries -- the large Persian Gulf OPEC producers and Mexico -- state energy industries still dominate the sector.¹² In the case of Mexico, state control appears to have hindered development of oil resources, as observed in sharply downward revisions to recent reserves estimates.¹³ Likewise, the ability of the state-controlled petroleum industry in China to supply oil and gas is falling further behind the country's increasing demand. The large prospective Tarim oil field in western China has so far been disappointing. Further increases in production there and in older fields may depend greatly on moving to more flexible independent market-oriented firms and attracting foreign expertise in exploration and development.¹⁴

Figure 1-1
Excess World Oil Production Capacity



Source: *Oil and Gas Journal*, Worldwide Petroleum Industry Outlook, 1997.

Technological Influences

With the world oil market becoming more competitive, cost-conscious and interdependent -- the role of technological factors has grown profoundly. It would be hard to overemphasize technology's effects on the finding, producing and storing of energy reserves. Some of these improvements in technology include advances in exploration techniques, deep water offshore drilling capability, multi-directional drilling, enhanced oil recovery, just-in-time inventorying, and the effects of information technology.

Examples that illustrate the extent of technological impacts particularly well are seismic exploration and offshore capability. Before 1980, seismic exploration represented in two dimensions (2-D) was the basis for all major petroleum exploratory and production well-drilling and field management decisions. Since that time, advances in techniques and computational power have made it possible to represent data in three dimensions (3-D), which in concert with multi-directional drilling has greatly

improved oil extraction rates. Recent advances in seismic data acquisition and processing have made it possible to add the dimension of time (i.e. 4-D, or time-lapse 3-D), which is essential for optimal field management, or to use both shear wave and pressure wave data (the so-called 4-component, or 4-C seismic) to better ascertain whether a formation contains oil, gas or water prior to actually drilling.¹⁵ Likewise, advances in deep water drilling capability have stimulated new interest in the Gulf of Mexico, as well as offshore Angola and Brazil, among other locations.

Supply of Oil to California

California is a relatively distinct petroleum market. According to refinery submittals to the Commission in 1997, about 88 percent of the crude oil feedstock for the state's sophisticated refining industry came either from in-state, much of it heavy and sulfuric, or from Alaska, mostly moderate in weight and sulfur. The remainder of the state's oil comes from a wide

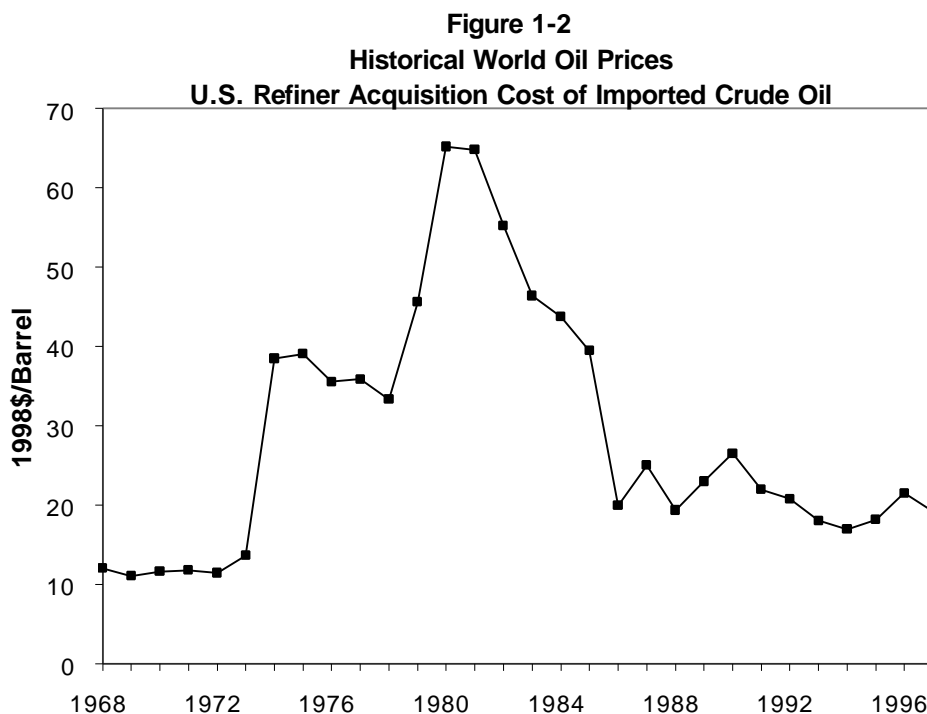
variety of foreign regions, such as Latin America, Southeast Asia and the Middle East.

The quality of the average crude oil refined in California, especially that received from in-state production, has historically been less desirable than in other US refining regions. Hence, prices are lower than for an “average” internationally-traded oil. The state’s complex refineries have adapted to processing low-to-moderate quality crude oil into the strictly-specified highway fuels required by the world’s most rigorous air quality regulations. As in-state and Alaska oil production decline, California will need to expand imports of similar quality oils, with Mexico and Venezuela increasingly likely nearby suppliers (Chapter 2 discusses future trends in more detail). This shift is part of a longer term trend, whereby Western Hemisphere sources of US imports grew from 37 percent in 1987 to 54 percent in 1996, largely at the expense of Middle East sources.¹⁶

WORLD CRUDE OIL PRICES

Historical Crude Oil Prices

Figure 1-2 shows one index of the price of oil since 1968, expressed in “real,” or inflation-adjusted, dollars. The data suggest that the history of the world crude oil market since then can be divided into three periods, which differ primarily in the pricing regime that determined world oil prices. These periods are the pre-OPEC period (through 1973), dominated by oil price controls and oil company feedstock price stability; the OPEC period (1974–1985), dominated by the rise of nationalized oil industries and OPEC official pricing; and the post-cartel period (1986 to present), when spot market-based pricing, influenced increasingly by futures markets, has prevailed.



Source: DOE/EIA, *Monthly Energy Review*, various issues.

This latest period appears to balance the extremes of previous decades, without the consistently low crude oil prices and unfettered petroleum demand growth of the pre-cartel period, but also without the political and economic instability of the cartel period. The reasons for this change include the effects of lifting price controls in the US and elsewhere, the growth of commodities markets, and the role of technological advances in increasing non-OPEC production and reducing the energy intensity of economic growth. These and other market-directed responses made the first two periods unsustainable, while creating the strong possibility that the dynamics of the post-cartel period will persist.

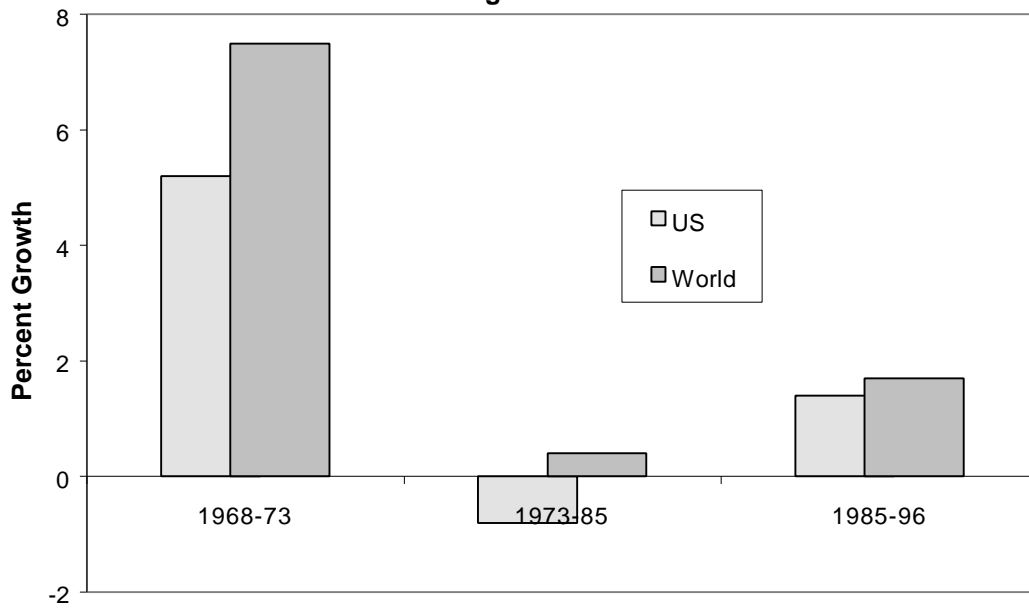
For instance, Figure 1-3 shows how US and world demand for petroleum products responded during these different periods. Likewise, OPEC's share of world oil production (including lease condensates) went from 56 percent in 1973, to 30 percent in 1985, then climbed back to 42 percent by 1996.¹⁷

Summary statistics for crude oil prices are very sensitive to the time period selected. For instance, the average real oil price for 1968-97 is \$28.82 per barrel (all prices referred to in this chapter are in inflation-adjusted 1998 dollars). The standard

deviation, or measure of variation above and below the average that encompasses about two-thirds of the historical price data, is \$15.68 -- a very large value. The average for the post-cartel period (1986-97) is substantially lower at \$20.86 per barrel and the standard deviation is only \$2.91. The average for the period since the Persian Gulf War (1991-97) is even lower, about \$19.51 per barrel, and the standard deviation is only \$1.95. These statistics indicate that long-term average real oil prices have been steadily declining since about 1980, with narrowing price variation.

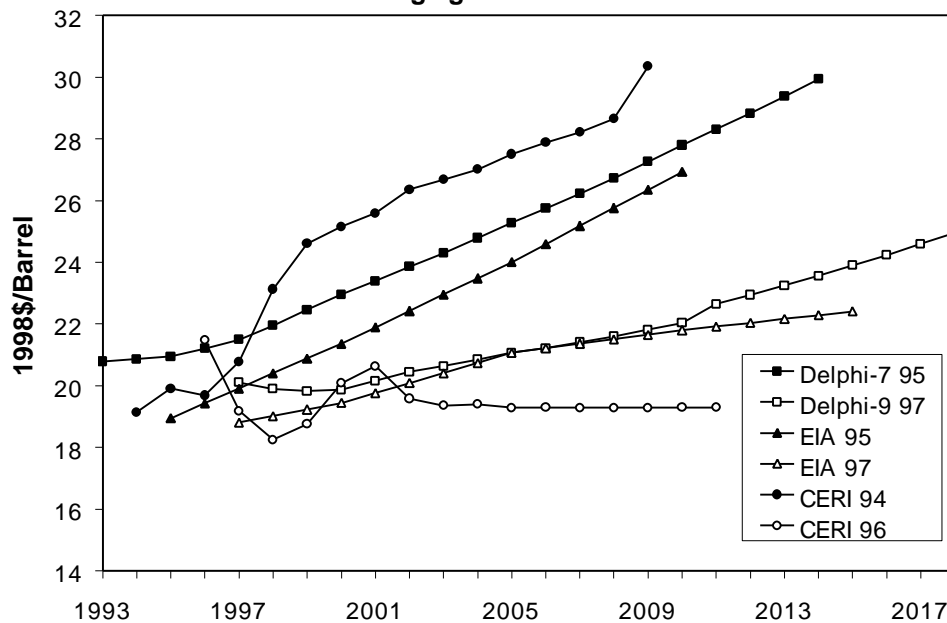
Average prices so far for 1998 have been very low (less than \$14 per barrel), due to weak Asian demand, recent mild winters, increasing Iraqi exports and high inventory levels. Even unprecedented agreements between OPEC and some non-OPEC producers to scale back exports have failed to do much more than establish a soft floor under the price decline. The chart of historical oil prices reveals, though, that market mechanisms limit prolonged deviations from long-term equilibrium prices. If current low prices persist, demand will tend to increase, more expensive production will be shut in, and industry investments could be delayed.

Figure 1-3
Demand For Refined Petroleum Products
Average Annual Growth



Source: American Petroleum Institute, *Basic Petroleum Data Book*, July 1997.

Figure 1-4
Changing World Oil Price Forecasts



Source: California Energy Commission, *Delphi Oil Price Survey* (1995, 1997); U.S. Dept. of Energy, Energy Information Administration, *Annual Energy Outlook* (1995, 1997); Canadian Energy Research Institute, *World Oil Market Projections* (1994, 1996).

Addressing Uncertainty in Future Oil Markets

A variety of credible long-term world oil price forecasts is available in the energy literature. A clear trend, however, can be found by examining changes in these forecasts since the **1995 Fuels Report**. Figure 1-4 compares recent reference case forecasts of the Commission's Delphi Survey, the Department of Energy's Energy Information Administration (EIA) and the Canadian Energy Research Institute's (CERI) with versions completed two years before. All results exhibit expectations of lower world oil prices, with growth rates that are flatter than previous projections.

Table 1-1 lists other recent oil price forecasts compiled by the Department of Energy. These projections reinforce the expectation of moderate to low real oil prices well into the future.

An alternative approach to these "single-point" forecasts for addressing future uncertainties in the world oil market is scenario planning. Past scenario

planning efforts can provide insights into the broader events that shape global oil market outcomes, including effects on prices. The most detailed scenarios developed by the Commission appeared in the **1989 Fuels Report** and were entitled "OPEC Resurgence" and "Global Economic Cooperation." The world of constrained energy supplies, OPEC-managed markets and steadily increasing real oil prices envisioned in the OPEC Resurgence scenario has not come to pass. A strong case, though, can be made that the world oil market has been experiencing an outcome very much like the Global Economic Cooperation scenario.

Economic growth, as envisioned in the Global Economic Cooperation scenario, is driven by technological development. Increasingly free trade and reduced trade barriers lead to increased transfer of clean, efficient technologies, especially to developing countries. Energy intensities continue to decline, with environmental premiums for clean fuels and technologies and a widening gap between crude oil prices and costs of fuels to end users. Abundant

Table 1-1
World Oil Price Projections (2000-2020)*
1998 Dollars Per Barrel

Organization	Index	2000	2005	2010	2020
DRI/McGraw Hill	Ref Acqn	18.03	20.09	21.97	27.28
WEFA Group	Ref Acqn	19.13	19.86	20.61	22.22
Gas Research Institute	Ref Acqn	17.78	17.79	17.78	---
Petroleum Economics, Ltd	Brent	15.96	14.57	13.70	---
Petroleum Ind. Research Assoc.	WTI	20.35	19.33	19.95	---
Natural Resources Canada	WTI	21.25	21.25	21.25	21.25
International Energy Agency	n/a	18.96	18.96- 27.87	18.96- 27.87	---
NatWest Securities	n/a	19.83	19.83	19.48	18.94

Ref Acqn = US composite refiner acquisition cost of crude oil

Brent = UK Brent oil

WTI = West Texas Intermediate

n/a = unknown

*Source: DOE/EIA, *International Energy Outlook 1998*, p. 38.

oil and other energy supplies, due to decreased finding and producing costs, reduce OPEC's leverage and encourage OPEC and oil-consuming nations' mutual dependence. The market exhibits moderate oil price volatility, but also low-to-

moderate oil prices and no long-term real oil price growth.

The fundamental assumption driving this view of the global economy is the existence of an effective and positive synergy among market economics,

technology dissemination and environmental policy. In other words, efficient technology addresses both economic and environmental problems. Economic growth simultaneously funds investment in new technology and increases demand for environmental amenities. Environmental improvements, in turn, increase long-term economic welfare. The logic behind these outcomes, coupled with an open oil pricing regime, drives the current world oil market, provides sustainability, and affirms trends found in the historical data and recent forecasts.

In a joint study by the World Energy Council (WEC) and the International Institute for Applied Systems Analysis, these basic assumptions were also used in developing themes for global oil market scenarios.¹⁸ Although the WEC study had a much longer planning horizon (50-100 years) compared to the Commission's 20-year forecast horizon, common expectations include:

- Steady economic growth
- Technology development costs decline and energy efficiency continues to improve
- Primary energy supplies do not limit economic growth or the flexibility of energy responses to various policy challenges
- Energy end use continues its historical trend toward more flexible, convenient and clean forms of energy

The WEC study finds that several energy strategies can meet the world's energy needs, including those that respond to the threat of global warming. Within the "shorter" planning horizon of the Commission, however, global energy markets will have only partially evolved after 20 years, and oil price volatility will remain a concern.

Commission World Oil Price Projections

Numerous variables affect the world oil market, including demand for crude oil, political stability of major oil exporters, potential oil resources (including the effects of technological advances), changes in petroleum industry structure, and trends in economic

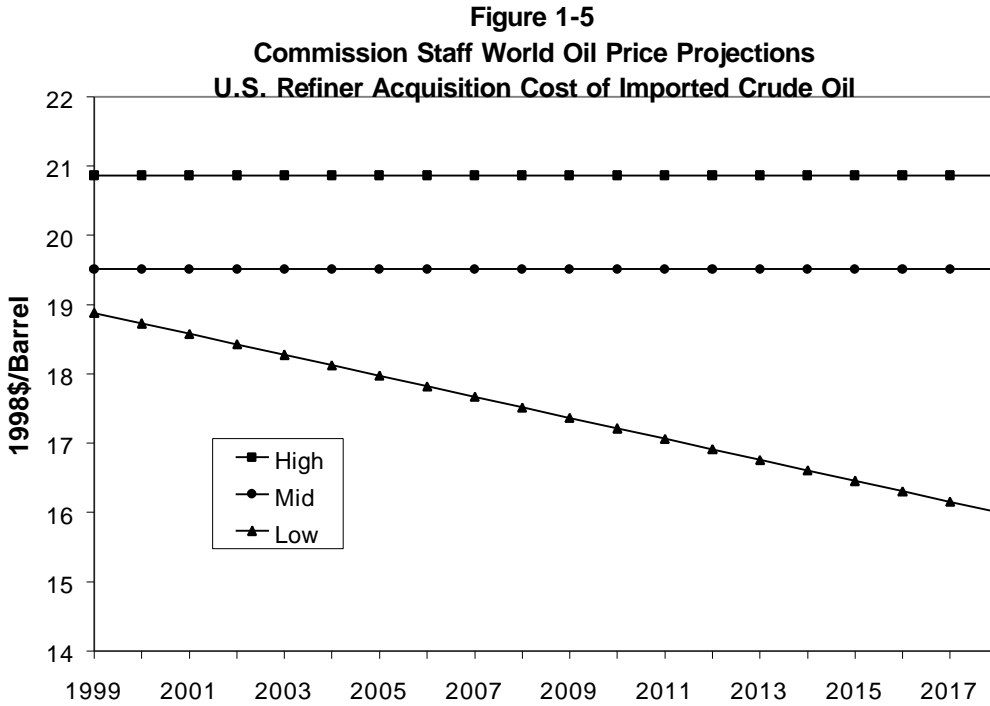
and environmental policy. Commission staff analysis of these variables indicates that departures from world oil price trends of the last ten years are conceivable, but strong feedbacks will work to limit their impacts. Technology improvements are capable of delaying the return to unacceptably high levels of OPEC market share for many years although that share will increase. Demand reducing policies, such as fuel taxes or more costly environmental rules, will persistently nibble away at the growth in total world oil demand -- even as steady economic growth just as persistently adds to it.

Because of these feedbacks in the market, the proposed world oil price forecasts and estimates of price volatility extrapolate trends derived from historical data. The high- and mid-case price projections are flat in inflation-adjusted terms. The high price case reflects the average for 1986-97 at \$20.86 per barrel for the US refiner acquisition cost of imported crude oil, while the mid price case is the average for 1991-97 at \$19.51 per barrel. The low price case shows a decline in real terms from \$19.03

per barrel initially to \$16.00 per barrel in 2018. Figure 1-5 compares the trajectories of long-term average prices for these three cases.

These projections of flat or declining long-term real oil prices, however, are based on assumptions of significant price variation in the short-term. Price variation can be measured statistically by standard deviations. As noted previously, the expected standard deviation in the high price case is about

\$2.91 per barrel; for the mid- and low-cases, it is about \$1.95 per barrel. These statistics indicate that in the mid-case, for example, average annual prices can vary between \$15-23 per barrel but would mostly range between about \$17-21 per barrel. Daily prices in a "low" or "high" price year for the mid-case would be expected to vary likewise so that daily spot market prices could be outside even those wide ranges. These would still be consistent with the long-term mid-case price equilibrium, unless they persisted over long periods of time.



Source: California Energy Commission, *California Petroleum Transportation Fuels Price Forecasts*, publication #P300-98-008, May 1998.

This potential for short-term price variation around generally moderate long-term oil prices may aggravate consumer perceptions of vulnerability and financial damage during those periods when high prices become visible in prices of products such as

gasoline. It is also just as likely to be taken for granted during periods of low gasoline prices. The absence of significant price volatility in crude oil and petroleum product markets, however, is extremely unlikely.¹⁹

Chapter 2

OIL SUPPLY OUTLOOK FOR CALIFORNIA

From a broad perspective, the long-term oil supply outlook for California remains one of declining in-state and Alaska supplies leading to increasing dependence on foreign oil sources. Estimates of the date when foreign sources will predominate the California market, however, have been lengthened compared to the previous *Fuels Report*. The principle factor at work in the time extension is a slower decline in Alaska oil supply. The following sections discuss the outlook in detail, including in-state, Alaska and foreign oil supply possibilities. From these supply trends, the staff identifies related marine transport issues that may be on California's horizon.

IN-STATE OIL SUPPLY

Current Trends

Before considering California future oil supply trends, a brief look at current trends can be instructive. Federal offshore production, which accounts for 18 to 20 percent of in-state oil supply, has varied significantly over the past few years. It accounted for all of the increase in in-state production in 1995, but all of the decrease in 1996 and 1997. In 1998, it again accounted for most of the 3 percent total production decline. The expectations of 90,000 barrels per day of sustained production from the Point Arguello field did not materialize, and production today is half what it was just two years ago. While still more than twice the volume of state offshore production,

federal offshore results lowered California's total production volumes.

The total California oil production declined in 1996, 1997 and 1998, falling from 351 million barrels in 1995 to 330 million barrels in 1998.²⁰ These results represent an approximate 2 percent annual decline. Onshore production in 1996 and 1997, however, increased as heavy California crude oil prices fluctuated around a higher average price than the preceding five years. In 1997, onshore production increased 0.8 percent (or 2 million barrels) from 1996. In 1996, the gain was closer to 2 percent (or 4 million barrels) over 1995 results. California heavy crude oil prices, represented by Kern River 13 degree gravity oil, in 1995 were closer to \$13 per barrel throughout the year, while 1996 and 1997 prices ranged between \$14 and \$19 per barrel. Since that time, however, prices for heavy California crude oils have dropped steeply with a 1 percent onshore production reported for 1998. The price drop is causing significant concern on the part of oil producers who have incurred large earnings reductions, scaled back on capital investments and cutback on the work force.

The 1996 and 1997 onshore production gains were not enough to offset the decline in federal offshore production, which dropped by 8 million barrels in 1996 and 9 million barrels in 1997. Most of the decline in both years occurred in the Point Arguello and Pescado fields. In 1998, federal offshore production dropped another 7 million barrels. These results continue the trend of declining total production that began in 1985, but at a rate that has slowed since 1990. The 4 percent

per year decline between 1985 and 1990 has averaged 0.8 percent per year over the last eight years.

One regulatory measure that has been undertaken to keep production decline rates low includes reduced royalty rates. Lower royalty rates offer an incentive for producers to return shut-in wells to service and extend the operation of economically marginal wells. In March 1996, the Bureau of Land Management (BLM) approved reduced royalty rates on 20 degree and heavier California heavy crude oil produced from federal leases. The royalty percentage was reduced on a sliding scale from 12.5 percent of the value of production for 20 degree oil to 0.5 percent for 6 degree gravity oil. The change applies to 55,000 barrels per day of production, or 6 percent of total California production. The BLM has announced plans to continue the rate reduction, citing a DOE study on stripper well production in new Mexico. The agency attributed most of the 24 percent increase in cumulative production to the existence of royalty reductions.²¹

Another helpful undertaking from an oil production perspective has been the establishment of a West Coast Petroleum Technology Transfer Council (PTTC). Located at the University of Southern California, the West Coast PTTC represents a clearinghouse of information and technical assistance targeted to California's small oil producers to solve geophysical, environmental and other problems to improve operating efficiency, reduce finding costs and boost oil recovery. Focusing on the potential of California's thousands of stripper wells and based on technical concerns raised by a producer advisory group, the PTTC uses workshops, the internet and other means to distribute technical information and link producers with consulting services.

Despite these positive signals, the current financial woes of smaller producers caused by low oil prices is resulting in calls for possible government action to preserve this industry group. Independent producers are particularly impacted by low prices because they rely solely on the value of oil for their livelihood, having no refining and marketing earnings, as do major integrated companies. The California Independent Petroleum Association (CIPA) has requested federal and state agencies to further study this matter. The Commission has shared relevant data on California's petroleum supply trends with CIPA as a first step in understanding the causes of today's historic low California heavy oil prices.

Future Trends

In the long-term, California production is expected to continue to decline as world oil prices remain flat. The decline is expected to range between 1 and 3 percent per year over the 20-year horizon. The low end of this range is slightly lower than the previous **Fuels Report**. This revision is because of the historical production trend over the past eight years and the positive efforts previously noted to slow the production decline rate.

The high end of the production decline range remains unchanged from the previous **Fuels Report** and reflects a future of continued low prices. It may be argued that the upper end of the decline rate could readily exceed 3 percent per year if California crude oil prices do not rebound soon. This position is well founded among many smaller volume producers. If California's largest volume producers also exhibit significant production declines, a steeper total decline rate should be considered in subsequent oil supply forecasts. Existing production data, however, do not support a higher value at this time.

A forthright means of estimating the upper and lower limit of the long-term contribution of in-state petroleum resources then is to assume low demand growth, 1 percent per year, for petroleum products and a 1 to 3 percent annual average decline rate for California supply. This demand growth assumption differs from previous forecasts of unchanging, or slightly declining, petroleum product demand prepared by the Commission. The current expectation is that transportation sector fuel demand, responsible for 80 percent of total petroleum product use, will increase gradually over the forecast period as California's human and motor vehicle populations continue to increase. The current transportation fuel demand forecast is presented in Chapter 4.

The increasing demand assumption also applies to additional markets currently supplied by California refineries. In-state refineries process crude oil into products for export to Arizona and Nevada. Because it is not possible to isolate the source of crude oil once it is refined into exported product to neighboring states, the demand increase assumption must apply to those markets as well.

Gradual demand growth and a 1 percent annual oil supply decline rate change the in-state oil contribution from 51 percent in 1998 to 36 percent by 2017. This represents a decline of 45 million barrels per year, from

332 million barrels in 1998 to 287 million in 2017. Using the 3 percent per year supply decline rate reduces the in-state contribution to 24 percent by the end of the forecast period, a 134 million barrel per year reduction from 1998.

Table 2-1 shows an abridged version of California's in-state oil supply trend with gradually increasing demand and three possible supply decline rates. The near-term increase, reported in the 1 percent per year decline rate example, reflects full use of the new Pacific Oil Pipeline. This new pipeline, completed in January 1999, will carry additional heavy California crude oil from Bakersfield to refineries in Los Angeles. While the pipeline does not translate into greater oil production, it will affect the near term contribution that local production makes to California's oil supply. This result is possible because some in-state oil being exported to West Texas will be redirected to Southern California, keeping more barrels within state borders. Figure 2-1 displays the long-term oil supply trend based on the 1 percent rate decline for in-state production and 1 percent annual demand growth.

The Governor, Legislature and several state agencies, including the Energy Commission, supported lifting the long held federal ban on exporting Alaska North Slope (ANS) oil to foreign markets. The ban was eliminated in April 1996, and shipments began one month later with the first (a 1.3 million barrel contract) sent by British Petroleum (BP) to the Chinese Petroleum Corporation of Taiwan. Additional contracted shipments to two South Korean firms followed with ANS exports averaging 70,000 barrels per day from July 1996 to June 1997.²² BP recently completed an agreement with China's petroleum company (SINOPEC) for 7.2 million barrels through 1998 (an average of 15,000 barrels/day) and is currently exporting 80,000 barrels per day, or 15 percent, of its Alaska production to Taiwan and Korea.²³

Alaska Oil Production Forecast

The Alaska Department of Natural Resources' (ADNR) oil production forecasts show a less severe decline rate than two years ago.²⁴ The May 1998 forecast shows a 5 percent average annual decline in total Alaska oil production. The 1995 ADNR forecast, cited in the previous *Fuels Report*, indicated a decline rate of 12 percent per year. Forecasts in the intervening years have revealed progressively lower decline rates. The difference between the 1995 and 1998 forecasts translates into 419,000 more barrels per

ALASKA OIL SUPPLY

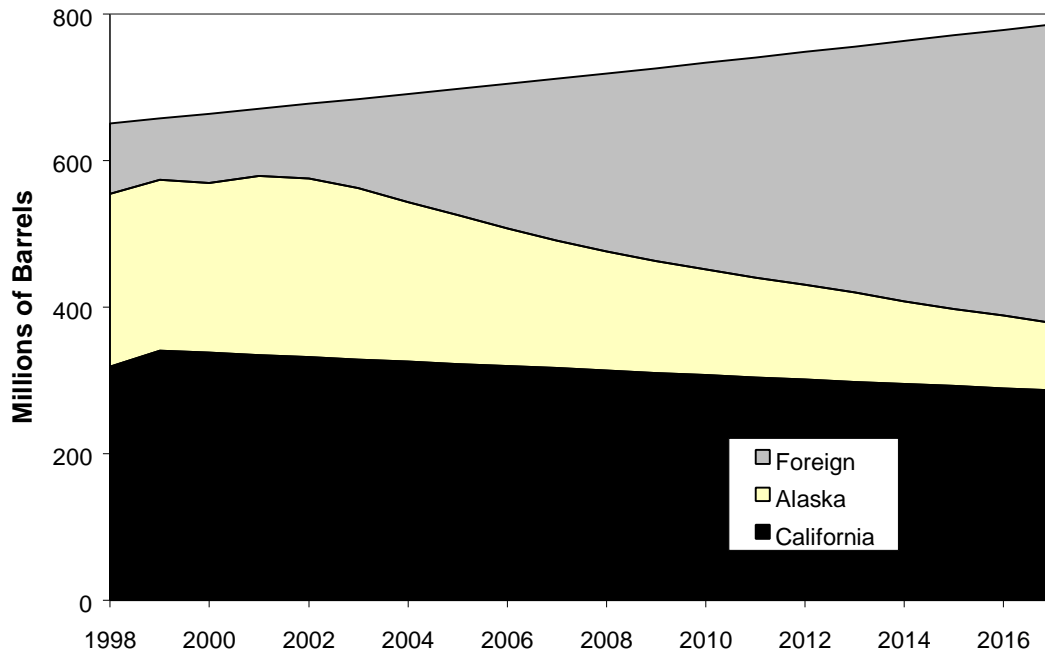
ANS Oil Exports

Table 2-1
California Oil Supply Ranges
Millions of Barrels

Year	California Refinery Receipts	1 Percent Per Year Decline Rate	California Supply	
			2 Percent Per Year Decline Rate	3 Percent Per Year Decline Rate
1997 (actual)	644.6	332.0	332.0	332.0
2000	664.1	338.0	328.6	319.5
2005	698.0	322.7	299.5	277.9
2010	733.6	307.4	267.6	236.6
2017	786.5	286.5	232.3	191.2

Source: Commission staff analysis.

**Figure 2-1
California Oil Supply Sources**



Source: Commission staff analysis.

day being produced in the year 2015 than previously envisioned. In other terms, the current forecast shows volumes over three times greater in 2015 than expected just three years ago. Nevertheless, production volumes are expected to still be much lower in the future than they are today.

In the short-term, the ADNR forecast indicates that Alaska production will post an increase of 71,000 barrels per day from 2000 to 2001. Most of the increase is attributed to anticipated production from the Alpine and Northstar fields of the North Slope. The gain, however, is expected by the ADNR to be short-lived with production again dropping in subsequent years.

Alaska Oil Supply to California

Since 1989, California refineries have received approximately half of Alaska's total production. If this trend remains unchanged into the 20-year future, then supply volumes to California would decline by 61 percent from current levels. This figure represents a volume reduction of 144 million barrels, from 236 million barrels in 1998 to 92 million barrels by 2017. Again, as California (and Arizona and Nevada) petroleum product

demand grows slowly, then Alaska's contribution to the market would decline from 36 percent in 1998 to 12 percent by 2017. This reduction represents the staff's baseline estimate.

California, however, could receive greater volumes of oil from Alaska than currently expected. One possibility is that California may attract more than half of Alaska oil production in the future because we are the major market for Alaska oil despite the end of the foreign export ban. Some companies also have both Alaska production and California refining capabilities. With increasing California product demand, Alaska crude oil producers would continue to find California a preferred market. In 1997, California consumed 13.8 billion gallons of gasoline!

Another possibility for receiving larger than expected volumes of Alaska oil is that Alaska production may decline more slowly than currently forecasted. The staff considered the effect of a 4 percent per year average Alaska production decline rate to gauge the sensitivity of this factor to California's foreign oil import future. At this rate, by the end of the forecast period, Alaska oil would represent 14 percent of total supply compared to 12 percent in the baseline case. The logical outcome

from reducing Alaska's production decline rate is a postponement of California's dependence on predominantly foreign oil supplies. The extent of the postponement can be estimated by considering the combined effects of several California and Alaska supply possibilities. The following section brackets the time range of foreign oil import growth.

FOREIGN OIL SUPPLY

In the distant past, California received significant supplies of low sulfur foreign oil from Indonesia. With the completion of the Trans Alaska Pipeline, however, foreign imports were nudged out by northern domestic supplies. Foreign imports remained, but represented only 5 percent of total supply. Since 1992, foreign imports have gradually increased as both California and Alaska supplies have declined. Even though California receives a total of 20 million fewer barrels of oil today than in 1992, the foreign component has more than doubled, representing about 12 percent of total supply in 1997. The remaining parts of California's future oil supply question include the following: **When could foreign oil sources exceed California's oil supply from Alaska and when may foreign oil imports be expected to exceed California supply?** A range of responses can be defined from the broad assumptions mentioned previously regarding California and Alaska supply trends.

The Commission staff assembled six sets of supply and demand conditions to develop a range of foreign oil import possibilities over the next 20 years. Three sets are shown in Table 2-2 and are inclusive of the nearest and furthest point in time for a crossover from domestic to predominantly foreign oil. While price is an integral part of oil supply and demand, the set of conditions identified in Table 2-2 are not based on a specific price forecast.

Foreign supply could exceed Alaska supply to California in 2006 and could exceed in-state oil supply by 2012. The crossover from Alaska to foreign supply occurs one year sooner in the high import case. The most dramatic change, however, is seen in the crossover between foreign and California supply under a 3 percent annual production decline for California. In this instance, the 2012 estimate for both the baseline and low import case becomes 2007, or five years sooner than if California supply declines at 1 percent per year.

From these results, it also becomes possible to estimate when foreign oil supplies could exceed the halfway mark in California's total oil supply picture. In the baseline case, this estimate is shown in Figure 2-2. In the low import case, foreign supplies do not exceed more than half of total supplies within the 20 year future, but in the high import case the time frame is shortened to 2011.

MARINE TRANSPORT ISSUE

California refineries receive about half of their total oil supplies by marine tankers. These supplies are off-loaded at marine terminals and transported by pipelines to refineries. As California petroleum product demand increases and in-state crude oil supplies decline, marine tanker deliveries will increase. Based on the supply possibilities shown in Table 2-2, the rate of import growth varies between 2 to 3 percent per year, while the total demand increases at 1 percent per year. In volume terms, the total demand by the end of the forecast period becomes about 136 million barrels per year higher than today. The total import volumes, however, increase by 168 to 257 million barrels per year as a larger portion of total demand is met by foreign suppliers.

The disparity between demand and import growth raises questions about possible capacity constraints of marine terminal facilities to handle increased oil and/or product imports and the public response to related increases in tanker traffic. Imports of 168 million more barrels per year are expected by 2017 based on a very gradual decline in California in-state supply. This volume translates into the equivalent of approximately 220 more oil deliveries to California ports per year in 2017 based on the use of medium class size tankers (about 120,000 dead weight tons). The 257 million barrel estimate means 337 more tanker deliveries per year, about one per day. Related questions on terminal storage and pipeline capacity constraints also surface when evaluating these long-term oil supply trends.

Table 2-2

California Oil Supply Possibilities
Millions of Barrels

Year	Domestic Supply					Foreign Supply		
	Petroleum Receipts		California		Alaska	Baseline	Low Case	High Case
	1% annual growth	1% decline rate	3% decline rate	Half of 1998 ADNR forecast	Half of 4% average decline forecast	1% CA decline and 1998 ADNR forecast	1% CA decline with 4% Alaska decline	3% CA decline with 1998 ADNR forecast
1998	651.0	318.8	312.4	236.0	237.9	96.2	94.4	102.7
1999	657.5	*341.2	328.6	232.9	228.4	83.5	88.0	96.1
2000	664.1	338.0	319.5	231.8	219.2	94.3	106.9	112.9
2001	670.8	334.9	310.6	244.7	210.5	91.1	125.4	115.4
2002	677.5	331.8	302.1	243.8	202.0	101.8	143.6	131.6
2003	684.2	328.7	293.8	233.6	194.0	121.9	161.6	156.8
2004	691.1	325.7	285.7	217.4	186.2	148.0	179.2	188.0
2005	698.0	322.7	277.9	203.3	178.7	172.0	196.5	216.7
2006	705.0	319.7	270.4	188.2	171.6	197.1	213.6	246.4
2007	712.0	316.8	263.0	174.7	164.7	220.6	230.5	274.3
2008	719.1	313.6	251.5	162.6	158.1	242.9	247.4	305.1
2009	726.3	310.5	243.9	152.6	151.8	263.3	264.0	329.8
2010	733.6	307.4	236.6	144.0	145.7	282.2	280.5	353.0
2011	740.9	304.3	229.5	136.5	139.9	300.1	296.7	374.9
2012	748.3	301.3	222.6	129.4	134.3	317.7	312.8	396.3
2013	755.8	298.3	215.9	121.9	128.9	335.7	328.6	418.0
2014	763.4	295.3	209.5	113.0	123.8	355.1	344.3	441.0
2015	771.0	292.3	203.2	105.5	118.8	373.2	359.9	462.4
2016	778.7	289.4	197.1	99.5	114.1	389.9	375.3	482.2
2017	786.5	286.5	191.2	92.0	109.5	408.0	390.5	503.4

*The 1999 increase in domestic supply reflects use of Pacific Oil Pipeline.

Source: Commission staff analysis.

The Commission should continue to evaluate the economic, environmental and energy policy implications of oil import growth and potential crude oil and product transportation and storage constraints.

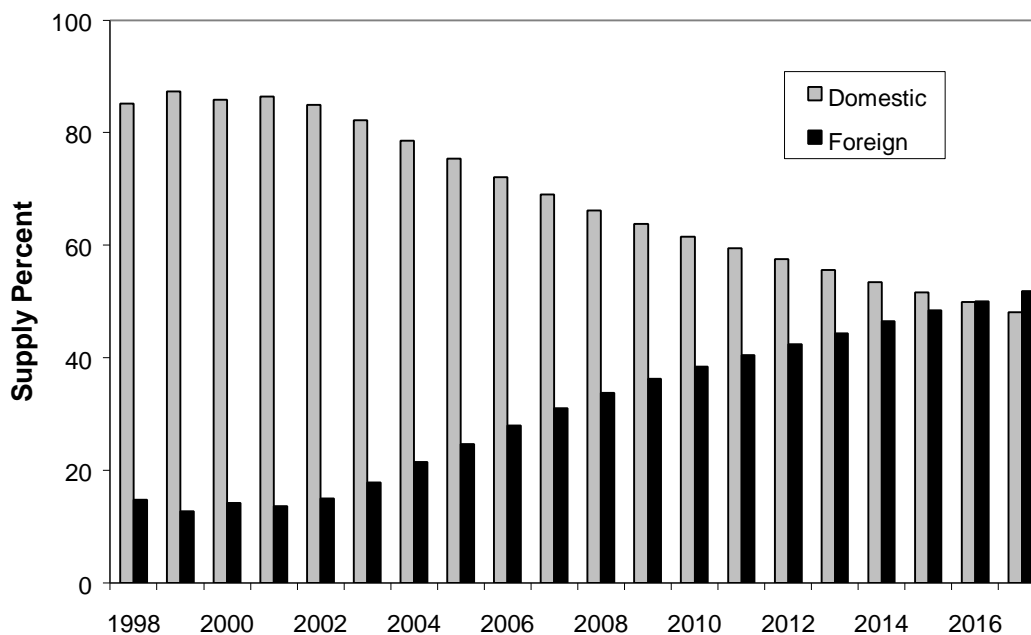
CONCLUSIONS

Because of changed expectations for Alaska oil production, the staff concludes that foreign oil imports should not exceed supplies from Alaska until 2006, given gradually increasing demand and current oil

production forecasts. Foreign imports are not expected to exceed in-state supplies until 2012 or comprise over half of California's total oil receipts until 2016. Previous forecasts of Alaska production revealed much sharper decline rates inferring a greater dependence on foreign oil by 2001. Although current estimates push the crossover point to predominantly foreign supplies back several years, the overall trend of diminishing domestic supplies and increasing foreign imports remains unchanged.

Short-term oil supply trends may differ greatly from those presented here. For example, in recent years,

Figure 2-2
California Domestic and Foreign Oil Trend



Source: Commission staff analysis.

California onshore production has increased because of higher overall oil prices. More recent data, since March 1998, however, reveal that California heavy crude oil prices have fallen dramatically to less than \$7 per barrel. These price conditions negatively affect production, as well as employment and tax collections -- features that lose visibility in long-term forecasts which "smooth out" what the oil producing industry hopes to be short-term conditions.

While oil price was not explicitly incorporated into these supply forecasts, the outlook for world prices in the long-term does not offer reassurance that domestic production will reverse its decline on a

sustainable basis. Greater foreign oil dependence, however, does not necessarily mean higher consumer prices and may mean lower prices. This notion can be confirmed by the world oil price forecast in Chapter 1 which reflects expectations of moderate, if not declining, long-term average international oil prices. Lower consumer fuel prices make more funds available to other segments of our economy while leaving small oil producers in financial jeopardy. As dependence on foreign oil increases, California can expect to see a variety of South American and Middle Eastern supplies entering California ports and an increase in marine tanker traffic.

Chapter 3

PETROLEUM FUEL PRICES AND VOLATILITY

This chapter summarizes the staff's long-term petroleum fuel price forecasts and then discusses petroleum product price volatility issues. The petroleum fuels price forecasts are based on projected prices for crude oil available to California. The staff has analyzed price volatility because California's unique gasoline and diesel fuel specifications have the potential to lead to significant variations over time in retail fuel prices.

PETROLEUM FUEL PRICE FORECAST

The petroleum fuel price forecast is based on three long-term projections of crude oil prices discussed in Chapter 1. The petroleum fuels represented in the forecast include: California Air Resources Board (CARB) Phase 2 reformulated gasoline, CARB-specification reformulated highway diesel, railroad diesel, agricultural diesel, commercial kerosene jet fuel and fleet propane. Table 3-1 summarizes the forecasts.

In these fuel price forecasts, assumptions must be made regarding the following factors:

- the rate of real growth in federal and state excise and sales taxes

- trends in distributor and/or dealer markup
- regulatory changes affecting fuel specifications.

Federal and State Taxes

In the high and mid-price cases, the staff assumed constant real federal and state excise taxes, rising in nominal terms to keep pace with inflation. This assumption is consistent with historical trends in highway fuel excise taxation.²⁵ The low price case assumes that no new excise taxes are imposed so that excise taxes decline in real terms. State sales taxes, which are levied as a percentage of retail prices, are assumed to remain constant on a percentage basis in all cases.

Currently, the average state sales tax of about 7.9 percent of the sales price is paid on all petroleum fuel types, but federal and state excise taxes vary by fuel type. Combined federal and state excise taxes for CARB gasoline are currently 36.3 cents per gallon; for CARB reformulated diesel fuel, these taxes total 42.3 cents per gallon; and for propane, they equal 19.6 cents per gallon. Railroad diesel fuel is subject to a federal excise tax of approximately 6.9 cents per gallon with no state excise tax. Agricultural diesel fuel incurs neither federal nor state excise taxes. Commercial jet fuel is subject to a

federal excise tax of 4.4 cents per gallon, but no state excise tax.

Table 3-1
California Petroleum Product Price Projections
 1998 Dollars Per Gallon

Case	1999	2008	2018
High Price			
CARB 2 Gasoline	\$1.37	\$1.37	\$1.37
CARB Diesel	\$1.45	\$1.45	\$1.45
RR Diesel	\$0.88	\$0.88	\$0.88
Ag Diesel	\$0.91	\$0.91	\$0.91
Jet Kerosene	\$0.86	\$0.86	\$0.86
Fleet Propane	\$1.02	\$1.02	\$1.02
Mid-Price			
CARB 2 Gasoline	\$1.31	\$1.31	\$1.31
CARB Diesel	\$1.36	\$1.36	\$1.36
RR Diesel	\$0.83	\$0.83	\$0.83
Ag Diesel	\$0.84	\$0.84	\$0.84
Jet Kerosene	\$0.79	\$0.79	\$0.79
Fleet Propane	\$0.94	\$0.94	\$0.94
Low Price			
CARB 2 Gasoline	\$1.29	\$1.18	\$1.08
CARB Diesel	\$1.33	\$1.18	\$1.03
RR Diesel	\$0.81	\$0.74	\$0.67
Ag Diesel	\$0.82	\$0.77	\$0.72
Jet Kerosene	\$0.76	\$0.69	\$0.62
Fleet Propane	\$0.90	\$0.77	\$0.63

Source: Appendix A of the Commission Staff Paper *Petroleum Transportation Fuels Price Forecasts*, May 1998, Publication #P300-98-008.

Distributor/Dealer Markup

Assumptions regarding distributor and/or dealer markup can have significantly differing impacts on final retail prices projected over time. The baseline assumption in all forecast cases has been to maintain a constant markup in real dollar terms. The markup for all fuels, except propane, was slightly lower in the low- and mid-price cases when compared to the high price case. The markup for gasoline ranged from 17 to 21 cents per gallon. The diesel fuel markup used was 15 to 19 cents per gallon and jet fuel was 6 to 8 cents per gallon. The propane markup was assumed to be 25 cents per gallon.

Environmental Regulation

The current price projections do not incorporate the

effects of potentially significant changes to fuel specifications to meet new or revised environmental regulations. This shortcoming may become significant given recent concerns over methyl tertiary butyl ether (MTBE) which is the oxygenate currently used in California reformulated fuels. If oxygenate requirements are changed, price projections for all petroleum products used in California will require revision in future reports.

The current forecast also does not include the potential effects of policies that may be implemented to meet US commitments to reduce greenhouse gas emissions. Unless lower cost alternative fuels, efficiency measures and/or greenhouse gas emission trading rules can effectively lower demand for targeted petroleum fuels, the pump price of these fuels may have to increase, by raising per gallon taxes or other fees faster than the rate of inflation so that they rise in real terms. On the other hand,

ongoing success in lowering demand for petroleum fuels would also tend to lower the commodity component of their price over time.

PETROLEUM PRODUCT PRICE VOLATILITY

All fuel users recognize that petroleum product prices vary over time. Factors contributing to this volatility are the price of the crude oil from which these products are refined, refining maintenance and unplanned outages, seasonal and annual demand fluctuations, and changes in the markup and taxation of products. For CARB phase 2, gasoline factors other than oil prices have a pronounced effect on the variation in product price. Price variation for other products can almost wholly be explained by changing oil prices. Even for CARB phase 2 gasoline, oil prices are the most important factor behind price variations.

Based upon historical variations in oil prices, the staff quantified the amount of corresponding fuel price variation associated with the high, mid and low oil price paths. In the high price case, reformulated gasoline prices are expected to vary between \$1.29 to \$1.45 per gallon, or 8 cents above or below the \$1.37 price identified in Table 3-1. In the mid-price case, reformulated gasoline prices could vary between \$1.26 and \$1.36 per gallon, or five cents higher or lower than the \$1.31 price shown in Table 3-1. In the low price case, a 10 cent total price variation is also expected, although retail prices decline over time in this case. All of these ranges are based on two standard deviations from the long-term average price, meaning that almost all of the expected average annual fuel prices fall within these ranges.

The influence of oil price on the volatility of the remaining fuels was also quantified. All categories of diesel fuel could cost 20 cents more or less per gallon than shown in the high price case. The variation in the low and mid-price cases are plus or minus 13 cents per gallon. Commercial grade kerosene jet fuel could vary by 24 cents per gallon in the high price case to plus or minus 15 cents per gallon in the other cases. Propane prices could vary by 23 cents per gallon in the low- and mid-price cases to 35 cents per gallon in the high-price case.

PETROLEUM FUEL RESERVE AND PRICE VOLATILITY

Presently, the New York Mercantile Exchange and other markets trade futures and forward contracts in refined products. California's unique petroleum product specifications, however, segregate California from the national market. Refined products are not readily substitutable in California because of our stringent fuel requirements. At this time, there is no futures market for California RFG.

Over the last two years, gasoline and diesel prices have fluctuated widely, and this market behavior has not been accepted as reasonable or desirable by the public and large volume users of these fuels. The potential for greater price volatility of petroleum products has created the need to examine what, if anything, the state could do to ensure price stability in the marketplace.

To alleviate the adverse effects of volatile prices, the Commission considered the creation of a regional petroleum product reserve. A study, sponsored by the Commission and conducted by Invictus Corporation, however, concluded that "...the proposed storage facility is not economically justified at present." Since the study's completion in 1993, however, significantly different market conditions -- in both the electricity and petroleum products markets -- have reopened interest in the concept of a California petroleum product reserve.

Starting in the 1980s, air quality regulations required electric utilities in Southern California to switch from burning residual oil to natural gas. This change left California electric utilities with large volumes of unneeded residual oil storage capacity. The unused residual oil storage is large, almost double current petroleum product storage capacity within the fifth district of the Petroleum Administration for Defense District.²⁶ Expanded inventories of gasoline and diesel could dampen price increases during periods of refinery production loss, thus providing consumers more stable prices.

Because these facilities already exist, the economic feasibility of a California petroleum product reserve (CPPR) came under question again. Utilities expressed interest in reevaluating the benefits of a product reserve because the 1993 Invictus study considered only the construction of new storage facilities in coming to their earlier conclusions. The staff examined the feasibility and possible price stabilizing effect of converting the existing electric utility petroleum storage capacity for refined petroleum products, namely CARB gasoline and diesel.

The staff divided the evaluation into four sections. These include:

- a volatility analysis (historical product price movements)
- a regression analysis to determine the variables that drive petroleum product prices
- a benefit-cost analysis
- an alternative to wet (physical) barrels in the form of futures and forward contracts specifically designed for California's unique petroleum product market

Volatility Analysis

The price volatility analysis considered gasoline and diesel prices occurring between 1992 and 1997 in Los Angeles and San Francisco. Both diesel and gasoline fuel price volatility increased in early 1996 when CARB reformulated gasoline specifications became effective.

Regression Analysis

The regression analysis revealed the driving forces behind petroleum product prices. Gasoline and diesel prices were regressed against crude oil prices, inventory levels, vehicle miles traveled and fuel consumption. The results showed that crude oil price is the driving factor with inventory levels influencing prices as well, but to a lesser degree. Changes in crude oil price explained between 55 and 90 percent of the changes in petroleum product prices.

Benefit-Cost Analysis

The staff completed a benefit-cost analysis to determine the economic feasibility of establishing a CPPR, given the large existing volume of storage available at electric utilities. Inventory requirements needed to lower product prices by a specific amount during an inventory release were calculated using the regression equations. This portion of the work estimated several parameters, including the total annualized cost of the reserve, the total benefits from lower prices during a petroleum product release, the total disbenefit to consumers when reserve restocking occurs since refilling the reserve would add upward pressure to product prices, and the benefit-cost ratio, or measure of economic feasibility.

The analysis considered price increases of 0 to 4 cents per gallon during restocking and price reductions of 4, 8, and 12 cents per gallon during inventory releases. The staff assumed one release per year and restocking that would take about one month. Based on a 20 year life, the cost of converting existing storage tanks, the cost of initial inventory and the cost of storage -- 30 cents per barrel per month -- the staff concludes that a product reserve would be marginally economic at best. Only when the ratio of benefits/costs is greater than 1.0 does the product reserve prove economical. If, during restocking, prices increase by more than two cents per gallon, the reserve would become uneconomic even if price reductions of 12 cents per gallon were realized during the product release. One factor not incorporated into the analysis, but that could further negate the benefits of a reserve, is refiner behavior. With a large California product reserve, refiners might lower their own inventories and offset the positive effects of a reserve.

Alternative to Wet Barrels²⁷

Annually, Californians consume over two billion gallons of diesel fuel and nearly 14 billion gallons of gasoline. The state's large refined product market creates the opportunity for an active paper market to develop. "Paper" transitions involve selling a commodity for future delivery. Such an action is generally referred to as a "paper" transaction because the sale is not accompanied by the near-term delivery of the commodity. The state can encourage the development of financial instruments, which participants can use for risk management.

Financial, or paper, markets allow consumers, large and small, to lock in price levels and thus insure against unexpected adverse price movements.²⁸ Generally, paper markets allow individuals and firms to transfer their exposure to price fluctuations to traders willing to accept this risk with expected compensation. Since traders hedge adverse price movements in both directions, financial instruments tend to stabilize prices. Financial instruments specifically designed for California's unique petroleum product market would provide refiners and consumers with greater risk management tools.

The trading of futures and forward contracts with differing characteristics and delivery points for similar products is not unprecedented. Contracts for WTI crude oil trade on the New York Mercantile Exchange, whereas contracts for Brent crude oil trade on the International Petroleum Exchange. These contracts differ in specifications and delivery points.

The Markets

Energy markets are usually divided into four sectors, one spot and three paper. The more widely known spot market has received considerable attention in past years. Equally important, however, is that paper markets have developed in the last decade. A brief description of the four markets follow.

Contracts in *physical (or spot) markets* usually require immediate delivery of the underlying commodity. Buyers and sellers agree on the term of delivery, usually through an intermediary. Spot delivery of the product will generally occur *soon*. In the case of petroleum or petroleum products, delivery will usually occur in the next pipeline delivery cycle, within 15 days, or by the end of the month, depending on the contract.

Contracts in *forward markets* usually require delivery at a future date, two months or one year from now. This paper market usually requires actual delivery of the underlying commodity as long as it meets the specifications stipulated in the contract. As with spot transactions, buyers and sellers use intermediaries in these transactions.

Futures Markets are really specialized forward markets. The contracts must, however, meet standardized specifications established by a

clearinghouse. Buyers and sellers do not know or even care who is at the other end of their transactions. In these markets, intermediaries play a major role since the contracts are traded on a specific exchange, the New York Mercantile Exchange. The actual delivery rarely occurs in futures markets; most contracts are settled by offset trades.

Over-the Counter Markets (OTC) share some of the characteristics of both forward and futures markets. Transactions in OTC paper markets resembles forward transactions because the principals (buyers and sellers) develop the transaction; however, the principles usually do not involve intermediaries such as brokers. In addition, these transactions are linked to prices in the future. Unlike forward transactions, OTC paper transactions are settled by payments of differences rather than by delivery of the commodity.

The Roles of Paper Markets

Unfortunately, many view paper markets in the same light as gambling casinos, where speculators profit at the expense of other market participants. This view tends to retard the development of paper markets. Paper markets for physical commodities promote both inventory building and price stabilization. By engaging in paper transactions, producers and consumers can transfer physical commodities from the present to the future by storing them. This function of *saving* commodities for a later day can stabilize price cycles if a sufficient number of players participate in the market and the market is large enough relative to consumption.

The existence of paper markets permits inventory levels to be greater than they might be in an environment where forward markets did not exist. If such markets were absent, many smaller participants would be unwilling or unable to hold stocks, and price fluctuations would be much greater. These characteristics were evident in agricultural markets in the last century before the development of liquid futures markets. Friedman and Schwartz, for example, note that interest rates and agricultural prices fluctuated dramatically, with crop prices falling and interest rates rising as the harvest approached because of the large cash demands of crop buyers.²⁹ Commodity prices would then rise and interest rates fall as the inventories were used up in the following year.

Inventories link paper markets to physical markets. Specifically, spreads between spot and forward or futures prices are correlated with the level of

inventories. Paper markets, thus, play an important role in risk management by altering the partially distorted view of these markets.

Chapter 4

PETROLEUM PRODUCT ISSUES

This chapter discusses several issues about fuels including fuel excise tax treatment of petroleum and alternative fuels and the cost and availability of alternative fuel vehicles. Additional issues addressed include the divestiture of retail gasoline stations from integrated petroleum companies, the measurement of market power in the petroleum industry, and the status of underground petroleum fuel tank replacements. A summary of the fuel supply and price implications of discontinuing the use of Methyl Tertiary Butyl Ether (MTBE) in California's petroleum fuels market is also included along with staff's petroleum transportation fuel demand forecast.

EXCISE TAXATION OF HIGHWAY TRANSPORTATION ENERGY

Excise taxes on transportation fuels fund highway construction and maintenance, mass transit projects, bridge replacements, safety research and many other items. Both federal and state excise taxes are applied to most transportation fuels including gasoline, diesel, compressed natural gas (CNG), Liquefied Natural Gas (LNG), ethanol, methanol and Liquefied Propane Gas (LPG). Electricity also serves as a transportation fuel but incurs no excise tax. For fuels that are taxed, disparities in the

amount of the tax and the disconnection from energy policy considerations at both the federal and state level have posed some contentious public debates.

The controversy centers around developing a means to balance the need for transportation-related revenues with sound energy policy and equitable fuel tax treatment. The questions that arise in fuel excise tax debate include: What is the appropriate method of determining excise tax rates for various fuel types? For example, excise taxes could be based on fuel energy content, on an applied usage basis, such as per vehicle mile traveled, or some other measure. Should some fuel types receive favorable treatment over others because of public health, environmental or energy policy considerations? If so, how would "underpayments" to the Federal Highway Trust Fund from any favored fuel type be compensated for by other fuel types? Is tax parity among fuel types a worthwhile goal? If so, what approach should be used for determining that parity?

Table 4-1 shows federal and state excise taxes that are now applied to transportation fuels. On a cents-per-gallon basis, diesel fuel is the most heavily taxed at a combined federal and state rate of about 42 cents per gallon. The staff also estimated rates on a dollar-per-million-Btu basis given certain assumptions on fuel Btu content and on a cents-per-mile basis and given assumptions on vehicle economy and fuel substitution factors, or the amount of another fuel required to replace one gallon of gasoline.

Depending upon the method used for comparison, the relative ranking of a fuel's federal and state combined tax rate often changes. For example, gasoline

Table 4-1
Current Federal And California Excise Taxes On Highway Energy

	Federal		State		Federal Plus State		
	Cents/Gal	\$/mmBtu (1)	Cents/Gal	\$/mmBtu (1)	Cents/Gal	\$/mmBtu (1)	Cents/Mile (2)
Gasoline	18.3	1.62	18	1.59	36.3	3.21	1.45
Diesel	24.3	1.86	18	1.38	42.3	3.24	1.24
Methanol (M 85)	9.15	1.40	9	1.38	18.15	2.78	1.22
Ethanol (E-85)	12.9	1.58	9	1.10	21.9	2.68	1.15
CNG	4.9/100scf	0.53	7/100scf	0.75	11.9/100scf	1.28	0.58
LNG	11.9	1.63	6	0.82	17.9	2.45	1.11
LPG	13.6	1.64	6	0.72	19.6	2.36	1.07
Electricity	0	0	0	0	0	0	0

(1) Dollars per million Btu calculated using the following heating values:

Gasoline (CA Phase II RFG): 113,000 Btu/gal

Diesel: 130,800 Btu/gal

Methanol (M 85): 65,400 Btu/gal

Ethanol (E 85): 81,870 Btu/gal

CNG: 92,800 Btu/100 scf

LNG: 72,900 Btu/gal

LPG: 83,000 Btu/gal

Other heating values are variously cited in the literature and would result in somewhat different \$/mmBtu comparisons.

(2) Cents per mile calculated using a gasoline fuel economy of 25 mpg, and the following substitution factors for other fuels (i.e. amount required to replace one gallon of gasoline in vehicular use).

Diesel: 0.73 gal

Methanol (M 85): 1.68 gal

Ethanol (E 85): 1.31 gal

CNG: 1.22 (100 scf)

LNG: 1.55 gal

LPG: 1.36 gal

Because of varying efficiencies of fuel applications in different engines, fuel substitution factors are estimates only. Use of other substitution factors will result in different mileage based comparisons. The above factors are representative of light-duty vehicles.

Note: This table does not include sales tax or local taxes collected on the sales price of most fuels.

Source: Commission staff paper, "Excise Taxation of Highway Transportation Energy Issues and Options for CEC," January 1998.

and diesel fuel switch first and second highest taxed positions using the dollar per million Btu and cents per mile comparisons. Methanol and ethanol move to higher tax positions and LPG and LNG to lower tax rankings using either of the other two methods shown.

Federal and state tax exemption provisions further complicate comparisons. One exemption applies if the fuel is used for off-road activity, such as farming or construction. Other exemptions are provided depending upon the category of fuel user. Federal

excise taxes are not paid by state and local government entities, school districts and other nonprofit educational organizations. Private local transit buses contracted by a state or local authority and private inter-city buses serving the general public along schedule routes are also exempt from the tax. Ethanol fuel, blended with gasoline or used in undiluted form, receives a partial exemption from the federal tax. State tax exemptions are even more complex and vary among fuel and entity types.

Besides posing headaches for those businesses and government agencies responsible for paying, collecting and accounting for excise taxes, exemption provisions influence the economics of fuel choices in some user categories. For example, gasoline costs to federal government vehicle fleets in California may be greater than the cost to state fleets because of differing exemption treatments. School districts pay less excise tax if they avoid gasoline use since they are exempt from paying federal and state excise tax on fuels other than gasoline. An additional intricacy occurs in California's excise tax statutes which provide an option for users of certain fuels -- CNG, LNG and LPG -- to pay a flat-rate annual fee in lieu of paying the excise tax. Ranging from \$36 to \$168 per vehicle per year depending on vehicle weight, this option can produce considerable tax savings for some vehicles which use large volumes of these fuels.

Whether all competing forms of highway transportation energy should be taxed at parity with gasoline or whether alternative fuels should be accorded temporary or even permanent tax relief remains unresolved. Because of the complexities in state and federal excise tax provisions and the seeming randomness of current tax structures, there is a need for a uniform, accepted basis for assessing excise taxes on all forms of transportation energy that is technically sound, fiscally responsible and supports rational energy goals. In the interim, new initiatives to address these issues are being considered at the federal level to provide tax breaks for alternative fuels.

The Commission should take an active role in bringing greater uniformity to federal, and especially state, excise tax determinations by undertaking the necessary technical analysis to develop an appropriate method of assessment and preparing consequent legislative proposals for excise tax revisions.

THE COST AND AVAILABILITY OF ALTERNATIVE FUEL VEHICLES

Legislation directs the Commission to conduct continuing studies on the cost and availability of alternative motor fuels, including cost comparisons of owning and operating alternative fuel vehicles (AFVs) versus gasoline vehicles. The following summary presents the staff's updated analysis using actual costs of AFV models available in California. More detail can be found in the staff paper ***Alternative Fuel Vehicle Cost Analysis Report***, October 1998.

The current market for AFVs is principally motor vehicle fleets operated by federal, state and local agencies; electric and natural gas utilities; and commercial businesses. Therefore, the staff focused on the costs incurred in fleet ownership of AFV options for automobiles, pickup trucks and vans with gasoline counterparts. The major assumptions include a five year ownership period, 15,000 miles of travel annually per vehicle and a 25 percent salvage value. The staff also assumed the same licensing, registration, insurance and maintenance costs for AFVs versus gasoline vehicles in the absence of conclusive data to the contrary.

The cost elements considered include vehicle purchase, operation and a series of other costs that do not vary much with mileage, such as insurance and registration costs. The vehicle cost used is the Manufacturer's Suggested Retail Price including destination and delivery charges and any incentives or discounts offered. Manufacturer discounts and incentives for the vehicles evaluated are from the 1998 ***Blue Book*** (3rd Edition). Some AFV models can be acquired only by lease, and in these cases the capitalized lease cost is used as the vehicle purchase cost.

Operating costs include retail fuel prices and vehicle maintenance. Table 4-2 lists the fuel prices used in the analysis which include sales and any excise taxes. Maintenance, insurance, registration and licensing costs are from the American Automobile Association publication ***Your Driving Costs***, 1998. Battery

Table 4-2
Retail Fuel Prices
1998 Dollars Per Gallon

Fuel	Retail Price
Gasoline	\$1.31
Methanol (M 85)	\$0.975
Ethanol (E85)	\$1.50
CNG	\$0.975 gasoline gallon equivalent
Electricity	\$0.068 per Kilowatt hour
Propane	\$1.21 gasoline gallon equivalent

Note: The electricity rate reflects typical rate to recharge electric vehicle batteries. Lower rate of \$0.04 per Kilowatt hour may be available for larger fleets in the off peak period.

Source: Commission staff report, *California Petroleum Transportation Fuels Price Forecast*, May 1998, and Commission staff paper, *On-Road and Rail Transportation Energy Demand Forecasts for California*, February 1999.

Table 4-3
Total Cost Difference Between AFV Model And Gasoline Counterpart
Cents Per Mile

Vehicle Type	Fuel Type				
	Ethanol	Methanol	CNG	LPG	Electric
Ford Taurus GL	+2.0	+0.8			
Ford F-150 Bi Fuel				+1.6	
Ford F-250			+2.1		
Ford F-250 Bi Fuel			+4.3	+7.1	
Ford F-350			+0.7		
Ford F-350 Bi Fuel			+4.5		
Ford Super Club Wagon			+0.4		
Ford Super Club Bi-Fuel				+5.4	
Ford Econoline E-250			+1.8		
Ford Contour Bi-Fuel			+4.0		
Ford Crown Victoria			+3.3		
GMC Sierra Pickup			+4.6		
Chevrolet C-2500 Pickup			+4.3		
Chevrolet Cavalier			+5.3		
Honda GX vs. Honda Civic DX			+5.7		
Saturn SC vs. EV-1*					+13.2
Toyota RAV-4					+17.1
Ford Ranger Pickup					+23.3
Chevrolet S-10 Pickup					+18.2
Honda Civic vs. EV Plus*					+13.7
*Models not directly comparable.					

Source: Commission staff draft report, *Alternative Fuel Vehicle Cost Analysis Report*, October 1998.

replacement costs for electric vehicles can be significant, but the data are not available in many vehicle categories and are not uniform in others. General Motors, for example, replaces batteries at no cost, i.e. battery replacement is incorporated in the lease rate. Honda does not. While battery life is less than vehicle life, battery replacement costs are not reflected in this short term analysis.

Table 4-3 summarizes the results of the staff's analysis. The data represent the cost per mile difference between each AFV and its gasoline counterpart or another vehicle with similar characteristics. The positive values in Table 4-3 mean that the AFVs are more expensive to own and operate than the gasoline version.

The Ford Taurus methanol vehicle, first available in 1993, with about 8,500 produced since that time, is more costly primarily because of higher fuel costs. The vehicle purchase price is also slightly higher than the gasoline model. Similar results also apply to the Ford Taurus ethanol vehicle, which was introduced in 1996. This vehicle will operate on gasoline in the near term because an ethanol fuel and retail distribution network remain undeveloped in California.

Compressed natural gas (CNG) vehicles available in California operate as either natural gas only vehicles or are bi-fuel, meaning they burn either natural gas or gasoline. While CNG is a lower cost fuel than gasoline, the total cost per mile for a CNG vehicle is more than its gasoline counterpart because of the higher cost of the CNG vehicle.

Liquefied Petroleum Gas (LPG) vehicles are also more costly to operate than gasoline vehicle counterparts. Higher fuel cost again results in higher cents per mile comparisons.

Electric vehicles currently offered in California include: General Motors' EV-1, the Chevrolet S-10 pickup truck, Toyota's RAV-4 EV, Honda's EV Plus, and Ford's Ranger EV pickup. The S-10, Ranger and RAV-4 may be compared with gasoline counterparts, but the EV-1 and Honda EV Plus are unique electric vehicles with no gasoline twin. For these two models, the staff selected a similarly sized gasoline model.

The disparity between gasoline and electric vehicle total costs is greater than for other AFVs. Total

costs range from 17 to nearly 25 cents per mile more to lease and operate an electric vehicle versus owning and operating a gasoline vehicle. Like CNG and LPG, the price of electric power is less than gasoline, but much higher electric vehicle prices override the fuel cost element.

Observations of the AFV Market

As of January 1998, slightly over 300 of GM's EV-1 vehicles were being leased in California. Honda plans to lease a similar number of its electric vehicle between 1998 and 2000. Some manufacturers are planning to offer new models of AFVs during the 1999 model year, including LPG and gasoline bi-fuel pickup trucks for fleet customers, CNG and gasoline bi-fuel pickup trucks, and another type of battery powered pickup truck.

AFV offerings may increase further as regulations increasingly restrict emissions. Currently proposed California regulations would prohibit all evaporative emissions beginning in 2003. At the same time, new, more strict CARB emission certification requirements for converting vehicles from gasoline to alternative fuels have contributed to the current lack of aftermarket conversion packages, which were previously available to the motoring public. Today, the limited slate of original equipment manufacturer models is the only route to obtaining alternative fuel capability.

RETAIL SERVICE STATION DIVESTITURE

Consumers object to the fact that gasoline prices are higher in some California locations than others. For example, gasoline in the San Francisco Bay Area is several cents per gallon more than in Los Angeles, even though 60 percent of the gasoline produced in California is produced by East Bay refineries. In comparison, Southern Californians consume 60 percent of the gasoline while this region produces only 40 percent of the state total. Likewise, in San Diego, gasoline prices are also several cents higher than in Los Angeles, even though the cost to transport gasoline from Los Angeles to San Diego by

pipeline is 1 to 2 cents per gallon and by truck about 2 to 4 cents per gallon.

Los Angeles County comprises the largest gasoline market in California, about 27 percent of the state's consumption. Major oil companies tend to price their product aggressively in this region in an effort to gain customers and increase their market share. Price differences, however, within any region can exceed price differences between regions. For example, prices tend to be higher near major transportation arteries. Consumers also consider convenience and advertising when deciding where to buy fuel. Some consumers appear willing to pay for the use of credit cards and credit card readers, convenience store sales, car washes, co-branded fast foods, gasoline additive packages, and brand loyalty.

The fact that gasoline is less costly in inflation-adjusted dollars than ever before is little consolation for many consumers. They contend that oil companies are taking advantage of them because they live in an area where higher prices for most goods are routinely expected. As a result, oil companies reason that consumers there will be willing to pay higher prices. Public complaints to legislators in Sacramento and Washington, DC indicate that consumers are not willing to pay more.

Because of these price differences, some independent retailers, and others, are calling for divestiture or separation of the wholesale sales function from the retail function for such vertically integrated oil companies. They believe that this divestiture will force more competition at the wholesale and/or retail levels. Some are also calling for "terminal pricing" where wholesale prices would be posted for specific brands, and anyone who has authority to purchase that brand at the wholesale level can go to that terminal and get fuel. If this notion becomes mandated by law, some consumers would no longer be able to benefit from wholesale price wars that oil companies sometimes engage in to garner market share. The Energy Commission is not aware of any definitive studies that have concluded that these market changes would lead to more uniform or equitable pricing.

The Commission should methodically evaluate factors other than oil prices that contribute to regional retail gasoline price differences and publish the results to better inform the public about how gasoline markets operate.

MARKET POWER IN THE PETROLEUM INDUSTRY

As a result of competitive pressures, many companies in the California petroleum production, refining and marketing industry are restructuring their organizations. Since early 1996, several firms either consolidated operations through mergers or established joint ventures. Mergers and joint ventures among large companies, in any industry, raise the concern of the possible exercising of market power by the re-structured firms, potentially stifling competition. Market power refers to the ability of companies to maintain prices above competitive levels for a significant period of time. Consolidating operations or establishing joint ventures does not automatically raise market power concerns. In some cases, mergers can enhance economic efficiency and, as a result, increase market competitiveness and lower prices for consumers. Policy makers, thus, must evaluate the impact on consumers of restructuring -- and concentration -- in the California petroleum products market before intervening.

Two measures of market concentration, the number of firms in a market and the market share of each firm, indicate the potential for the exercise of market power. The total market share of the top four firms in a particular industry and the Herfindahl-Hirschman Index (HHI) of the industry provide approximate indicators of market concentration. The indicators provide partial answers and usually only a more rigorous analysis can confirm or dispel the question of the exercising of market power.

The existence of market power is not illegal nor uncommon. Rather, it is the abuse of market power that is illegal. The following analysis does not address the complicated question of what constitutes such abuse, but offers two methods of measuring market concentration.

Intense competition in the petroleum products market is one factor driving the high level of oil company restructuring. In the past few years, generally poor financial results in refining and marketing have led to the closure of less efficient refineries (usually smaller, older ones) and a sizable decline in the number of gasoline stations in the US and elsewhere. More stringent environmental regulations have also played a role in some refiners'

decision to cease operating in the state. In 1990, 20 refiners produced gasoline in California while 13 do so now.

In 1996, several companies announced restructuring plans. In October 1996, Shell Oil Company and Texaco Inc. confirmed that the two companies were discussing a joint venture to operate some combination of their US oil refining and marketing assets, and UNOCAL Corp. announced its intent to divest itself, through spin-off or sale, of its entire refining and marketing operation. Subsequently, Tosco Corp. agreed to buy all the operating assets of UNOCAL's West Coast refining and marketing business, including three California refineries, 1100 gasoline stations, 13 oil storage terminals, and 1500 miles of oil pipelines. Beforehand, Tosco had one refinery in California, the 156,000 barrels per day facility in Avon in the San Francisco Bay Area. The deal made Tosco the largest independent refiner in the country.

In November 1996, Shell and Mobil Corp., in a cost cutting move, announced plans to combine most of their California oil exploration and production operations. Shell and Mobil are California's first and third largest oil producers, respectively. In December 1996, California refiner Ultramar Corp. completed a merger with Diamond Shamrock Inc. to form Ultramar Diamond Shamrock Corp., thereby becoming the third largest independent refiner in the US. The merger did not directly affect California because Diamond Shamrock had no refining or marketing operations in the state. Diamond Shamrock dominates the gasoline market in Texas, Colorado and New Mexico. The merger gives the combined firm geographic diversity, operating synergies, and cost savings from capital and operating efficiencies.

Shortly thereafter, in February 1997, reports surfaced that Ultramar Diamond Shamrock was negotiating to buy Total Petroleum (North America), Ltd., the North American affiliate of French oil giant Total SA. The acquisition cut costs for the combined firm and enhanced competition in the Mid-continent area, where both have a presence. In August 1998, British Petroleum and Amoco announced the creation of BP Amoco, creating one of the largest petroleum companies in the world. Numerous other examples could be cited, but these activities create sufficient interest in reexamining the level of market concentration.

Two simple measures provide a profile of market concentration in any industry. First, the total percent market share held by the four largest firms evaluates the potential for collusion. Many experts believe if this market share indicator exceeds 60 percent, market power can more easily occur. Second, the HHI examines relative market concentration. To obtain the HHI for an industry, an analyst sums the squares of the market shares of the individual firms. For example, an industry with one firm (a monopoly) will produce an HHI of 10,000 (100×100), and an industry with many firms and fairly evenly distributed market shares will generate an HHI close to zero.

The US Department of Justice (US DOJ) and the Federal Trade Commission (FTC) use the HHI to identify areas of concern regarding the ability of firms to exercise market power. The agencies emphasize, however, that market share and market concentration data must be used cautiously and flexibly because it may either understate or overstate the likely future competitive significance.

According to the Merger Guidelines published by the US DOJ and the FTC, a postmerger HHI below 1000 indicates an unconcentrated market, ordinarily requiring no further analysis of competitive effects. A postmerger HHI between 1000 and 1800 indicates a moderately concentrated market. Within this range, if a merger causes an increase in the HHI of more than 100 points, it raises significant competitive concerns and ordinarily requires further analysis. A postmerger HHI above 1800 indicates a highly concentrated market, in which case an increase in HHI of over 50 points due to a merger raises significant competitive concerns. It should be noted that the interpretation of an industry's HHI generates many controversies. Anti-trust experts do not agree on the proper threshold of the HHI. Some say the threshold is 1800, while others say it is 2500.

Calculating an HHI requires identifying the relevant product market and geographical market. Any products that are close substitutes for each other are considered to be in the same product market. Similarly, if a buyer can switch his purchases to a different location without a significant cost increase (for example, due to transportation costs), then both locations are considered to be in the same geographical market. The Guidelines stress the importance of an accurate determination of the product and geographical markets.

Once the market is determined, the shares of all firms in the market must be identified. Firms in the market include not only firms currently operating, but also firms that could enter the market quickly and inexpensively. Similarly, possible expansions of existing firms that could be accomplished quickly and inexpensively are also considered part of the existing market.

Crude oil exploration and production is a competitive industry, consisting of thousands of companies. Crude oil sales take place in a unified, worldwide market. In effect, every company is competing with every other company worldwide. This competition is one reason why OPEC is currently unable to regulate production sufficiently to control crude oil prices. The proposed oil company mergers should have no discernible effect on competition in crude oil production or sales.

Because refined oil products are more expensive to transport and store than crude oil, petroleum product markets tend to be more regional, or even localized, than oil exploration and production. A small number of large firms can dominate oil refining and marketing in a particular area. For this reason, this analysis focuses on potential market power in the refining and marketing segment of the California petroleum industry mergers.

The staff's analysis considered four different oil company configurations in California. Case 1 is the market as of the end of 1996. Case 2 is the same market except that Shell and Texaco are assumed to complete their proposed joint venture and operate as

one firm from the consumers (although not worldwide). Case 3 is the same as Case 1 except that Tosco and UNOCAL are assumed to combine California assets. In Case 4, it is assumed that both the Shell-Texaco joint venture and the Tosco-UNOCAL merger are in effect. The analysis focused on five industry parameters or products: crude oil refining capacity, retail gasoline sales, gasoline production, wholesale gasoline sales and diesel production. Table 4-4 shows the sum of the market shares of the four largest firms in the four cases, and Table 4-5 shows the HHI calculated for the same cases.

Results

As expected, consolidation increased both measures of market concentration. Table 4-4 shows that the four largest firms market share is well above the threshold of 60 percent, exceeding 70 percent in some cases. While the HHIs of Table 4-5 fall below 1800, all cases produce post-merger values that exceed the pre-merger value by more than 100 points. Actually, Case 4 numbers exceed the Case 1 numbers by 300 to 500 points.

According to the Merger Guidelines, the cases investigated suggest a moderately concentrated market since all values of Table 4-5 fall between 1000 and 1800. The increase of the post merger HHIs, however, indicates that the consolidation can enhance market power. Only a more rigorous analysis can confirm or disprove this notion.

Table 4-4
Total Market Shares Of Four Largest Firms
Percent

	Case 1	Case 2	Case 3	Case 4
Oil refining capacity	59	66	67	75
Retail gasoline sales	60	65	66	71
Gasoline production	57	64	67	73
Wholesale gasoline sales	61	67	69	75
Diesel production	61	64	71	73

Source: Commission staff analysis.

Table 4-5
Herfindahl-Hirschman Index

	Case 1	Case 2	Case 3	Case 4
Oil refinery capacity	1275	1404	1468	1596
Retail gasoline sales	1165	1298	1305	1435
Gasoline production	1224	1362	1449	1587
Wholesale gasoline sales	1214	1384	1425	1595
Diesel production	1198	1248	1648	1698

Source: Commission staff analysis.

To confirm or disprove the above market indication requires an analysis of the other factors (in addition to market concentration) that affect the creation or exercise of market power. Among these factors are the degree of sensitivity of buyers to the price of the product (price elasticity of demand), the amount of spare production capacity that could be pressed into service in response to rising prices, the availability of close substitutes for the product in question, the ease of entry into the market by new, competing firms, the existence of strong trade associations, and the rate of technological change (which could change existing industry patterns).

A more detailed analysis should include more exact definitions of market products and market geography. In particular, the assumption that the State of California represents the appropriate market area should be replaced by a quantitative geographical analysis. Experience over the last two years has shown that petroleum products, including limited quantities of California reformulated gasoline and diesel, can be produced elsewhere and profitably imported into the state under certain circumstances. The analysis also did not consider the possibility of new market entrants. Rectifying each of these shortcomings would likely lower market concentrations and thereby reduce calculated HHIs.

The Commission should conduct a more rigorous market power analysis of gasoline production and sales to confirm or disprove that existing merger activity enhances market power.

UNDERGROUND STORAGE TANK UPGRADING PROGRAM

According to US Environmental Protection Agency and California Water Resources Control Board rules formulated in 1989, underground petroleum storage tanks in the US must be replaced or upgraded to meet rigorous new standards of leak prevention and monitoring as of December 22, 1998. In California, state laws prevents any distributor from delivering petroleum products to underground tanks not upgraded and approved by the local agency (typically a county or city environmental health department) designated by the California Department of Toxic Substances Control as the lead in managing their Unified Program. As its name suggests, this program unites all toxic substances control programs within a single overall licensing process to simplify and standardize many complex regulatory procedures.

The Commission staff's concern is that station closures resulting from the inability to make required improvements will lead to situations, especially in more remote rural areas of the state, where consumers and public services -- such as fire, emergency, schools and other municipal services -- will lose access to refueling facilities. With this concern in mind, the staff has been working with other state and local agencies to determine the extent of the potential problem.

In 1996, over 11,000 retail service stations were operating in California. Faced with the deadline for upgrading petroleum storage facilities, many service station owners struggled to find the financing to make the necessary capital improvements. Also,

many public fleet fueling services closed and public fleet operators will now use commercial fueling stations. The Replace Underground Storage Tank (RUST) loan program administered by the California Trade and Commerce Agency provided financing for many of these stations, but demand overran available funds during the 1997-98 fiscal year. Presently, however, the Agency has received sufficient funding from the 1998-99 State Budget to fund existing requests.

The Commission staff has assessed available compliance data by geographical location to identify areas of concern. In most of these areas, the majority of existing stations will remain in business, having found appropriate financing one way or another. Continued funding of the RUST program should help this process.

For stations in some rural areas, remaining in business has involved going to aboveground tanks, which tend to be less costly and more straightforward to install than underground tanks where smaller capacity tanks (usually under 2000 gallons) are practical. The California Department of Forestry has also gone almost entirely to aboveground tanks. Most municipal services, on the other hand, have closed their tanks and will buy their fuel at retail sites in the future. Also, some stations at sites that have been only marginally viable over the years may yet have to permanently close. The potential for some remote areas to permanently lose refueling facilities remains a strong possibility. The Commission staff will continue monitoring these trends to determine whether serious problems of fuel availability will arise because of the upgrading deadline, and make any necessary recommendations.

MTBE AND FUEL SUPPLY AND PRICE

MTBE is an oxygenate in gasoline used to produce a fuel that complies with federal and state air quality standards. Its low cost and compatible blending properties have made it the oxygenate of choice of many petroleum refiners. It has recently been detected in groundwater, however, and at certain levels may pose public health risks or render drinking water unpalatable. At a legislative hearing that considered discontinuing the use of MTBE,

Commission staff testified on the potential for fuel supply shortages and price spikes that would accompany such an action. Following the hearing, the Legislature directed the Commission to comprehensively examine the potential gasoline supply and price impacts of the discontinuance of MTBE on consumers and evaluate alternatives to MTBE. A summary of the study results follows. The Commission staff report, *Supply and Cost of Alternatives to MTBE in Gasoline*, October 1998 contains greater detail.

In undertaking this study, the Commission considered California's refinery infrastructure, the supply and price of various alternative oxygenates, the capability to import finished petroleum products and blendstocks (needed to make California gasoline), and the ability of the existing distribution system to handle various MTBE substitutes.

The refinery infrastructure portion of the study involved designing and computer modeling several cases to simulate statewide refinery operations under differing economic and regulatory conditions. Oxygenates examined as possible substitutes for MTBE included ethanol, tertiary butyl alcohol (TBA), ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME). The staff also considered the effect of reducing MTBE use and eliminating the use of any oxygenate in gasoline. Assessing import capability entailed examining worldwide volumes of gasoline blending components available and the cost to supply them to California refineries. The staff studied the distribution system composed of marine terminals, pipelines, and railroad cars to determine the ability of this system to import, blend, and transport gasoline with oxygenates other than MTBE. The analysis derived the fuel cost impacts of substituting other oxygenates for MTBE under three time frames: near term (no phase-out time), intermediate term (3 years) and long term (6 years).

The study found that the cost impact on consumers relates directly to the time permitted to phase out MTBE. A near term phase out would produce dramatic consequences for consumers and the state's economy. Approximately 15 to 40 percent of California's gasoline supply would no longer be available, resulting in sharp price increases. Previous experience with temporary gasoline shortfalls of less than 15 percent resulted in 30 cent per gallon retail price increases. In the near term, refiners would be unable to obtain adequate ETBE,

TBA or TAME volumes to meet California's gasoline demand. Existing MTBE plant conversions, requiring between 1 and 2 years, would become necessary. Even though adequate, US produced ethanol volumes could be diverted to California, however, distribution problems caused by inadequate blending equipment would still remain. Actions to untangle these problems require 1.5 to 2 years to complete.

In the intermediate term case, gasoline supply and cost impacts are reduced. The change in the average cost of gasoline ranges from a decrease of 0.2 cents per gallon to an increase of nearly 9 cents per gallon, depending upon the type of oxygenate(s) considered and whether or not a complete oxygenate phase out is enforced. Average cost changes do not necessarily reflect the full change in retail gasoline prices because factors other than production cost influence retail price.

The cost increase associated with ethanol use ranges between 6.1 and 6.7 cents per gallon. The reliance on ETBE produces a cost increase of about 2.5 cents per gallon while TBA use produces a 0.5 to 1.4 cent per gallon average cost increase. An economically optimal assortment of oxygenates lowers the cost impact from a savings of 0.2 cents per gallon to an expense of 0.2 cents per gallon. Consumers in this case would either save \$30 million per year or incur an additional annual expense of the same amount. Under the reduced MTBE case, developed in response to pending House Resolution (H.R.) 630, the average production cost of gasoline declines by 0.2 to 0.8 cents per gallon. At the other extreme, a total elimination of all oxygenates produces a cost increase of 4.3 to 8.8 cents per gallon.

The long term case allows adequate time for the market to achieve a new supply and demand balance for a lower priced oxygenate. Oxygenate availability increases as production capabilities improve and suppliers meet gasoline demand by producing blending materials at California refineries and importing additional oxygenate as needed. For ethanol, the average cost increase for gasoline ranges between 1.9 and 2.5 cents per gallon while ETBE produces negligible cost impacts. Choosing TBA as the gasoline oxygenate produces an average cost increase of 0.3 to 1.0 cents per gallon. An optimal mix of oxygenates results in a cost decrease of 0.3 to 0.4 cents per gallon, or consumer savings of \$47 million to \$63 million annually. The H.R. 630 case results in a cost decrease of 0.3 to 1.5 cents per

gallon while discontinuing the use of oxygenates increases cost by 0.9 to 3.7 cents per gallon.

Quantifying the environmental impacts associated with the use of alternative oxygenates in gasoline is an important consideration as well. The Commission firmly supports the premise of improving energy systems that promote a strong economy and a healthy environment. Fuel supply must be both affordable and environmentally acceptable. From an air quality perspective, ETBE, TBA and TAME are comparable to MTBE in terms of emissions. Ethanol, at the current 7 pound maximum volatility limit, is also comparable. If refiners are permitted to produce gasoline with 10 percent ethanol and an additional pound volatility allowance, hydrocarbon and benzene emissions would likely increase due to greater evaporation along with greater exhaust emissions of nitrogen oxides. These findings are based on preliminary results of a vehicle test study conducted by the CARB.

As to water quality, most oxygenates considered behave like MTBE. They are able to mix with water, are difficult to remove, and produce an unpleasant taste and smell at very low concentrations. Water quality impacts were studied in great detail by the University of California. The study concluded that MTBE poses an environmental threat to ground water and drinking water.

Based on findings and recommendations of the University report, public testimony and regulatory agencies, Governor Davis signed an executive order on March 25, 1999 to remove MTBE from gasoline at the earliest possible date, but not later than December 31, 2002. The order calls for the Commission to participate with several other agencies on a task force to implement the order. The Governor's order specifically directs the Commission and the California Air Resources Board to develop a timetable for removing MTBE from gasoline that reflects the Commission's MTBE supply and cost study.

The Commission is also directed to evaluate by December 31, 1999 the potential for developing a California waste-based or other biomass ethanol industry. The evaluation is to include the steps necessary to develop this industry if ethanol is found to be an acceptable substitute for MTBE.

Table 4-6
High Gasoline Demand Scenario
 Statewide Transportation Fuel Demand

Year	Gasoline billion gallons	Diesel billion gallons	CNG million therms	Electricity million kWh
1997	13.2	2.5	9	459
2000	13.5	2.6	9	490
2005	14.4	2.9	9	547
2010	15.3	3.2	9	607
2015	16.3	3.3	9	671

Source: Commission staff report, *On-Road and Rail Transportation Energy Demand Forecasts for California*, February 1999.

Table 4-7
Low Gasoline Demand Scenario
 Statewide Transportation Fuel Demand

Year	Gasoline billion gallons	Diesel billion gallons	CNG million therms	Electricity Million kWh
1997	13.2	2.5	9	459
2000	13.5	2.6	33	642
2005	13.8	2.9	47	2,647
2010	14.1	3.2	53	4,329
2015	14.4	3.3	58	5,189

Source: Commission staff report, *On-Road and Rail Transportation Energy Demand Forecasts for California*, February 1999.

The Commission will fulfill the directives contained in the Governor's executive order relating to the timetable for phasing out MTBE in gasoline and evaluating the potential for developing a waste-based or other biomass ethanol industry in California.

PETROLEUM TRANSPORTATION FUEL DEMAND FORECAST

The staff prepared several transportation fuel demand forecasts using the California Light Duty Vehicle Conventional and Alternative Fuel Response Simulator (CALCARS) model, the California Freight Energy Demand model (for diesel) and the mid-price petroleum product fuel prices found in Table 3-1 of Chapter 3. The base case forecast includes two scenarios for light duty vehicles. Tables 4-6 and 4-7 summarize fuel demand by fuel type for the two scenarios.

The first scenario assumes no improvement in the fuel efficiency of new light duty vehicles and no significant entrance of alternative fueled vehicles. This high gasoline demand scenario produces a 1.2 percent per year increase in gasoline use. The second scenario assumes new vehicle fuel economy growth rates ranging between 15 and 28 percent over

the forecast period, depending on the vehicle class, and significant inroads in the use of alternative fuel vehicles. This low gasoline demand scenario results in a 0.5 percent per year increase in gasoline use. Thus, even with greater use of alternative fuel vehicles and steady growth in vehicle fuel economy, on-road gasoline demand continues to grow, exceeding 14 billion gallons per year by 2015 in the low case and 16 billion gallons in the high demand case.

The staff also modeled the effects of higher economic/demographic growth (relative to the base case) and continued growth in sales of sport utility

vehicles (SUVs) on gasoline demand separately. Annual gasoline demand under higher economic growth conditions, 0.5 to 0.75 percent higher than the base case, amounts to a 0.6 to 0.7 billion gallon increase (4.5 percent) over the base case scenarios by 2005. Comparisons beyond 2005 were not possible because more distant growth projections were not available. Extrapolating historical SUV sales trends (1984 through 1997) results in 1.4 million more SUVs making up the on road vehicle fleet by 2015 with a resulting 0.4 billion gallon (2.5 percent) increase in gasoline consumption compared to the high gasoline demand scenario.

Chapter 5

NATURAL GAS MARKET ANALYSIS

This chapter presents the Commission's natural gas market analysis and the forecast of natural gas prices and supplies for the period 1999 through 2019 for each end-use market sector in the state.³⁰ Regulatory issues are discussed, followed by results of modeling the North American natural gas market. These results provide wellhead prices and production from each major supply basin for the reference or base case. The natural gas price and supply forecast is then presented for each market sector in California. Detailed results for the power generation market are included for each natural gas service area. Similar detail for other market sectors is contained in the *Natural Gas Market Outlook*.³¹ Uncertainties inherent in the gas market are then discussed and provide an insight into the dependence of natural gas price and supply on future market changes.

The chapter concludes with a discussion of market fundamentals and the influence of major parameters that drive gas price, supply and demand from a continental and statewide perspective. Market fundamentals include parameters such as the need for interstate pipeline capacity, California's gas production outlook, overall demand for natural gas with emphasis on the power generation market, and the influence of resource availability, technology, and market structure on prices. The importance of natural gas marketing centers and their impact on price through increased competition is also briefly discussed.

REGULATORY ISSUES

Regulatory reforms in the natural gas market have been implemented slowly over the past two decades. Starting with wellhead price decontrol during the early 1980s, reforms are now progressing toward providing competitive market options to end users. These reforms have changed the way the markets function. The major proceedings now underway are the development of a state natural gas strategy by the California Public Utilities Commission (CPUC) and federal reforms by the Federal Energy Regulatory Commission (FERC) to further refine the interstate transportation market. These two regulatory proceedings will significantly impact the direction of the natural gas industry throughout the country during the next decade.

In California, the CPUC is investigating the current market and regulatory structure within the state, with the intent of adopting market-oriented reforms that will benefit all gas consumers. The CPUC instituted a rulemaking proceeding (R.98-01-011) in January 1998. The goals of this proceeding are the following:

- provide residential and small commercial customers with competitive choices as afforded to larger industrial and power generation customers;
- unbundle transportation, distribution and storage services to all customers;

- streamline regulation; and
- provide adequate consumer protection.

A critical issue arising out of this proceeding is how to define the future role of the natural gas utility companies and how to deal with the monopolistic structure of these utilities in a competitive market.

At the national level, interstate transportation has been deregulated six years with the implementation of Order 636. In July 1998, FERC issued a Notice of Proposed Rulemaking (NOPR)³² intended to eliminate cost-based regulation for transportation services less than one year, reduce the number of captive customers, and provide greater flexibility to allow pipelines to redesign services to better serve the needs of customers. To protect against the use of pipeline monopoly power, the NOPR seeks to retain cost-based regulation for long-term transportation arrangements.³³

As both of these proceedings are in the initial stages of investigation, the Energy Commission does not expect new natural gas rules to be adopted at the state or federal level for at least two years. In California, the ultimate resolution date for the CPUC rulemaking is more uncertain due to the signing of California Senate Bill 1602 (SB 1602) by Governor Wilson in August 1998. SB 1602 precludes the CPUC from issuing any gas restructuring decisions until January 2000. Similar legislation has been introduced in the current session that could extend the date an additional 12 months. These actions raise questions about whether the Legislature will craft legislation similar to what was done in 1996 to restructure the electricity market.

These regulatory reforms clearly entail a wide range of issues to be addressed before any action is taken by either regulatory agency. Of critical importance are issues related to rate design, interstate capacity holdings, potential bypass of utility systems by new or existing customers, unbundling utility services, and finally roles of the utility companies and gas (energy) service providers in the market.

For example, nearly 20 percent of natural gas consumed in the state is distributed to end use customers by non-utility sources. These include instate direct pipelines from producers to customers and the Kern River and Mojave interstate pipelines. The potential for large customers to by-pass the utility system raises the question of utility's ability to

recover their cost of service and whether remaining customers should pay for the shortfall in revenues from reduced throughput. These questions remain unanswered.

CONTINENTAL SUPPLY

Natural gas supplies are expected to remain plentiful for the next several decades. The total resource base, or gas recoverable with today's technology, for the lower 48 states is estimated to be about 975 trillion cubic feet (TCF), which is enough to meet current consumption levels for more than 50 years. Canadian resources are estimated at 419 TCF. Table 5-1 provides a detailed breakdown of resources by region.

While technical enhancements will continue to increase the size of the resource base, it is much less certain whether producers will be able to increase their production capacity at the rate needed to meet incremental demand. Several factors must be met during the long-term if production capacity is to increase. First, production from new wells must offset production declines from existing wells and increase by the level of incremental demand. Recent discussions in the natural gas industry have addressed concerns about whether drilling activity and the startup of new wells in key producing areas can offset reduced production from wells currently operating. In the Gulf Coast region, for example, some experts argue that new deepwater offshore production may simply offset declines throughout the rest of the region, rather than providing a net increase in the resource base.³⁴

Second, processing facilities and gathering, transmission, and distribution pipelines must be sufficient to take the gas from the wellhead to the burner tip. Rapid increases in drilling activity are useless if the gas is unable to be processed and placed in the pipeline network. Although the Rocky Mountains are expected to emerge as the second largest supplier of natural gas in the lower 48, unless pipeline and processing capacity is constructed, and gathering systems developed, this emergence will not be possible. The same conclusion is true of the deepwater region of the Gulf Coast. Major increases in production are projected, but cannot be realized in the absence of downstream facilities. While several

pipeline projects appear to support future growth in the Gulf region,³⁵ it is less certain whether new

Table 5-1
Lower 48 And Canadian Natural Gas Resources
Trillion Cubic Feet

Supply Region	Proved	Potential	Reserve Growth	Total	% of Total
Lower 48					
Gulf Coast	59.563	194.130	76.984	330.677	33.9
Rocky Mountain	15.028	168.854	7.436	191.318	19.6
Anadarko	28.087	23.135	52.745	103.967	10.7
Appalachia	7.006	69.719	3.794	80.519	8.3
San Juan	18.630	52.480	8.456	79.566	8.2
Permian	14.463	20.418	27.073	61.954	6.4
Northern Great Plains	2.149	53.624	3.946	59.719	6.1
North Central	2.003	24.131	2.370	28.504	2.9
California	4.613	18.920	1.334	24.867	2.6
Pacific Northwest	0.028	13.929	0.000	13.957	1.4
Lower 48 Total	151.570	639.340	184.139	975.049	100.0
Canada					
Alberta	52.886	180.318	27.026	260.230	62.1
British Columbia	10.670	48.155	1.538	60.363	14.4
Eastern Canada	5.000	12.780	0.721	18.501	4.4
Northern Canada	12.785	60.000	1.843	74.628	17.8
Saskatchewan	3.079	1.475	0.949	5.503	1.3
Canada Total	84.420	302.728	32.077	419.225	100.00

Source: Commission staff report, *Natural Gas Market Outlook*, June 1998.

facilities will improve prospects for Rocky Mountain production.

Finally, a larger share of natural gas industry research and development (R&D) budgets must be devoted to technology development. Unfortunately, the trend for future R&D spending is headed downward. During the past two years, Congress has indicated a preference to reduce exploration and production-related research by the Department of Energy. Additionally, the budget of the Gas Research Institute (GRI) has been reduced significantly and will, in the future, be funded on a voluntary basis.³⁶ These types of reductions, while not impacting technology advancements in the short-term, could impact the historical trend of technology advancements over the next 20 years.³⁷ Despite these concerns, the Commission's long-term supply analysis finds there are more than sufficient resources to meet the growing demand for natural gas. The Commission strongly contends that the gas industry will find the means to tap these resources and build the necessary facilities to fully meet future

natural gas demand. This undertaking will be accomplished through innovation, development of new exploration, drilling and development techniques, and the employment of completely new, yet to be developed, technologies.

Production from the lower 48 states is expected to increase from 17.1 TCF in the 1994 base year to 25.9 TCF in 2019. Gulf Coast and Rocky Mountain supply regions account for most of the increase during the next two decades. Alberta continues to provide the bulk of Canadian production. Canadian exports are projected to rise to 3.9 TCF in 2014 and remain at that level.

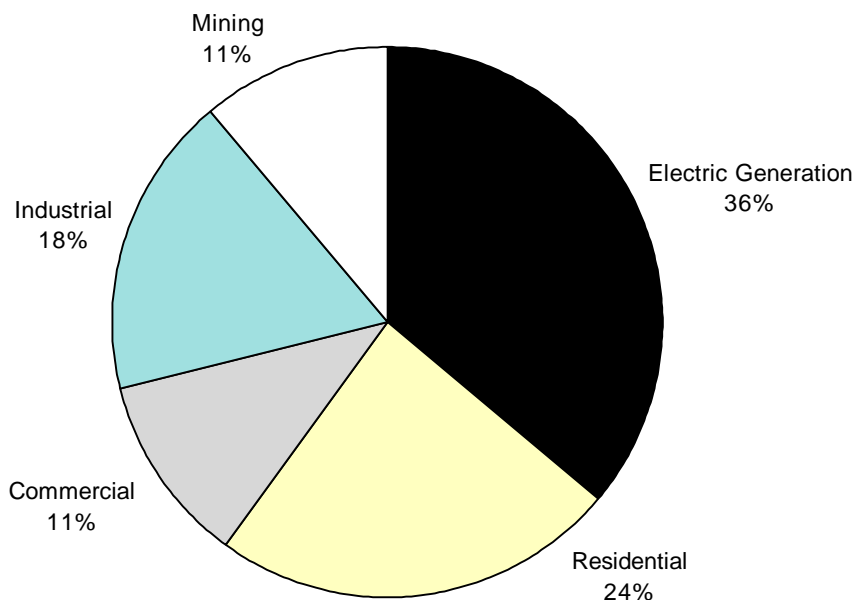
DEMAND

California is the second largest consumer of natural gas in the nation, ranking behind Texas. In 1997, the state consumed more than 5.5 Billion Cubic Feet

Per Day (BCF/D), the highest level reached since the drought year of 1994. Thirty-six percent of natural gas consumed in California generates electricity.

Another 24 percent serves the needs of residential customers. The remaining 40 percent is consumed

Figure 5-1
Natural Gas Consumption Shares By Sector



1997 total state consumption was 2.01 trillion cubic feet

Source: Commission staff report, *1998 Baseline Energy Outlook*, August 1998.

by the industrial, mining or resource extraction and commercial sectors (Figure 5-1).

The Commission expects that electricity generation needs will lead future growth in California's natural gas demand during the next 20 years. Statewide natural gas consumption, including all market sectors, is expected to increase by 1.3 percent per year through the year 2017, with much of this increase attributed to incremental electricity generation. Total daily natural gas consumption is projected to exceed 6 BCF/D by 2004 and 7 BCF/D by 2017.

While future growth in natural gas demand is expected to be driven by power plants using natural gas, a significant amount of volatility occurs in natural gas demand from year-to-year in this sector. This volatility can be attributed to the level of hydroelectric power available to the state each spring. In general, higher levels of precipitation during a given year leads to increased hydroelectric

power generation, resulting in lower natural gas need for electricity generation.

Excluding power generation requirements, the outlook for growth in natural gas demand is modest. During the next 20 years, demand (excluding power generation demand for natural gas) is projected to grow at less than 1 percent per year. The industrial sector, primarily the process-related industries, will be responsible for the bulk of the anticipated increase. Residential consumption is expected to increase by 0.7 percent per year.

PRICE

Table 5-2 shows a comparison of natural gas wellhead prices by region and in the aggregate. The average wellhead price is expected to increase 1.4 percent per year from \$1.65 per Thousand Cubic

Feet (MCF) in 1999 to \$2.18 per MCF in 2019. In Canada, the average price is projected to increase 2 percent per year in real terms from \$1.17 per MCF

in 1999 to \$1.75 per MCF by the year 2019. These growth rates are considerably lower than previous Commission estimates of 3 to 4 percent per year.³⁸

Table 5-2
Lower 48 And Canadian Wellhead Prices
Base Case
1998 Dollars Per MCF

Supply Region	1999	2004	2009	2014	2019
Lower 48					
Anadarko	1.73	1.93	2.16	2.33	2.51
Appalachia	2.32	2.47	2.67	2.76	2.87
California	1.96	2.14	2.33	2.54	2.74
Gulf Coast	1.68	1.85	1.99	2.10	2.17
North Central	1.91	1.99	2.06	2.14	2.19
Northern Great Plains	1.30	1.35	1.41	1.47	1.52
Pacific Northwest	1.85	2.06	2.23	2.43	2.56
Permian	1.58	1.75	1.96	2.16	2.31
Rocky Mountains	1.41	1.51	1.59	1.67	1.75
San Juan	1.38	1.52	1.67	1.87	2.06
Lower 48 Total	1.65	1.82	1.97	2.09	2.18
Canada					
Alberta	1.14	1.28	1.39	1.53	1.69
British Columbia	1.18	1.32	1.52	1.70	1.87
Eastern Canada	4.05	2.84	2.67	2.86	3.08
Saskatchewan	1.67	1.97	2.21	2.50	2.73
Canada Total	1.17	1.31	1.45	1.58	1.75

Source: Commission staff report, *Natural Gas Market Outlook*, June 1998.

The decline is due to the following two factors: (1) the use of reserve appreciation in the North American Regional Gas (NARG) model for the first time and (2) the change in owner/producer's discount rates used in the model. Figure 5-2 compares the current forecast with forecasts produced in the previous two *Fuels Reports*.

NATURAL GAS SUPPLIES AND PRICES AT THE CALIFORNIA BORDER

Four producing regions supply California with natural gas. Three of them -- the Southwest US, the Rocky Mountains, and Canada -- provide approxi-

mately 85 percent of all gas consumed in the state. The remainder is produced inside California.

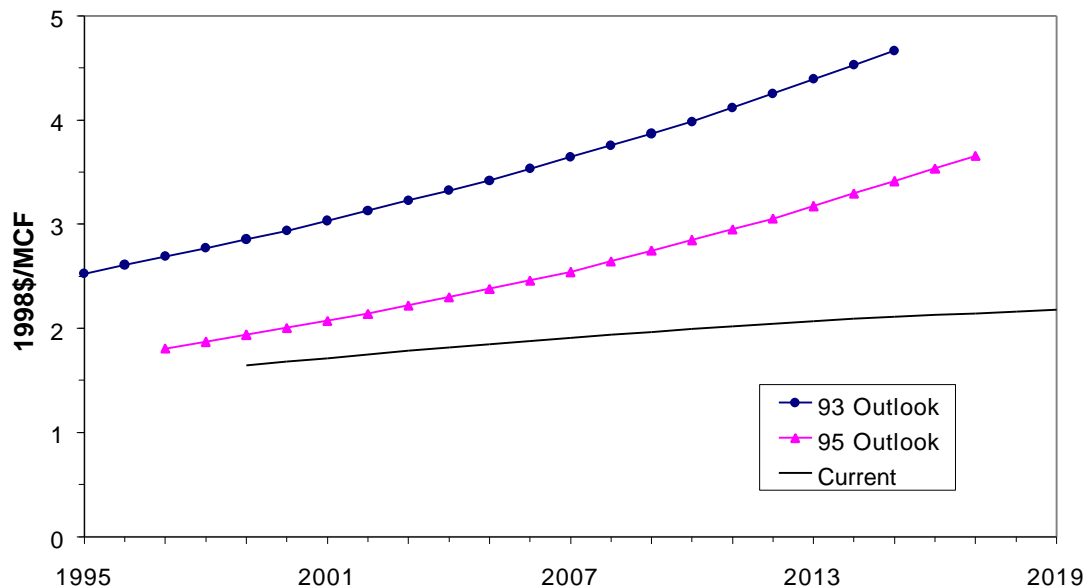
The staff expects adequate supplies to be available from each of the four regions providing gas to California during the forecast period. Supplies available to California are expected to increase from 5.9 BCF/D in the 1994 base year to 7.8 BCF/D by 2019. No significant changes are anticipated in the market shares of supplies coming from the Southwest, Canada, the Rocky Mountains and California producers. Southwest supplies will continue to dominate, retaining approximately half of the market. Canadian producers will supply another quarter of the market with the remainder being split between Rocky Mountain and California suppliers.

The ability of Southwest suppliers to maintain their market share of supplies to California during the next two decades will be helped by an emerging gas market in the northern part of Baja California. In July 1997, SoCal Gas completed construction of a 25

MMCF/D pipeline to deliver gas to the city of Mexicali. Another 275 MMCF/D of capacity is expected to be placed into service with the

completion of the power plant near Rosarito. As such, supplies to California include up to 157 BCF of gas delivered via California to northern Mexico.

Figure 5-2
Energy Commission
Lower 48 Wellhead Price Forecast Comparison



Source: Commission staff report, *Natural Gas Market Outlook*, June 1998.

Table 5-3
California Supply Sources And Border Prices
Base Case

Supplier By Producing Region	1994	1999	2004	2009	2014	2019
Production (Trillion Cubic Feet)						
California	0.311	0.257	0.341	0.343	0.375	0.388
Southwest	1.012	1.006	1.169	1.220	1.259	1.319
Rocky Mountains	0.243	0.255	0.290	0.307	0.331	0.353
Canada	0.590	0.544	0.604	0.705	0.767	0.795
Total Supply Consumed In California	2.156	2.061	2.403	2.574	2.732	2.854
Price (1998 Dollars Per MCF)						
California	n/a	1.97	2.19	2.42	2.66	2.89
Southwest	n/a	1.80	2.03	2.23	2.47	2.69
Rocky Mountains	n/a	1.87	2.09	2.30	2.52	2.74
Canada	n/a	1.63	1.81	1.97	2.19	2.39
Average Price At California Border	n/a	1.79	2.00	2.18	2.41	2.62

Source: Commission staff report, *Natural Gas Market Outlook*, June 1998.

Removing those volumes from the analysis reduces Southwest deliveries from between 72 to 105 BCF, beginning in 2004.

The Commission expects the average California border price to increase 1.9 percent per year from \$1.79 per MCF in 1999 to \$2.62 per MCF in the year 2019. Specific estimates of supplies and prices available to California by region appear in Table 5-3. The Southwest price represents a weighted average of gas entering California at Topock and Blythe. Canadian gas is priced at Malin near the Oregon border. The border price for Rocky Mountain gas is set at Wheeler Ridge, located inside California, at the terminus of the Kern River and Mojave pipeline system.

Need for Additional Interstate Pipeline Capacity to California

Despite the current excess interstate natural gas pipeline capacity, additional pipeline capacity will be needed at the California border during the next two decades. For example, additional capacity will be needed from the Rocky Mountains for Kern River Pipeline Company and from Canada for Pacific Gas Transmission Company by 2004 and 2009, respectively. Additional delivery capacity at Wheeler Ridge will be needed by 2009 to accommodate additional flows from these regions. No additional delivery capacity will be needed from the Southwest; however, expansion of the pipelines moving San Jan Basin natural gas to California will be needed by 2004. Additional capacity to receive increasing supplies of natural gas from the southwest supply basin will be needed on the SoCal Gas system at Topock by 2009.

Outlook for California Natural Gas Producers

Even though California production holds a proximity advantage over gas produced in other regions, in-state natural gas has lost market share during the past 11 years. In 1986, California natural gas satisfied more than one-quarter of consumer needs. By 1997, it supplied only about 15 percent of the California gas market. The steady decline in market share has occurred largely because of increased competition at the wellhead and contractual

restrictions between producers and PG&E. The restrictions precluded producers from gaining access to the spot market. As such, 1997 California production was 41 percent lower than it was in the mid-1980s.

Recent reports from the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (Division) suggest that the bottom of the market may have been reached. The Division reports that 1997 California natural gas production was 291 BCF, about the same level realized in 1995 and 1996. Removing offshore production from the picture, onshore production increased slightly to 242 BCF compared to the previous two years.³⁹

Looking beyond the present situation, the staff sees new hope for an upward swing in California production during the next few years. In Kern County, the February 1998 sale of the Elk Hills Naval Petroleum Reserve to Occidental Petroleum was finalized, privatizing one of three petroleum reserves previously established for the Navy. Considered the largest producing natural gas field in the state, as much as 200 MMCF/D of additional production will soon be sold on the open market. This production was previously reinjected at Elk Hills to produce crude oil. The field is strategically located in the heart of Kern County, which is directly connected to SoCal Gas and easily accessible by PG&E.⁴⁰

In Northern California, drilling activity is up for the first time in years. New permits for wells in 1997 were up 25 percent from the previous year. Higher natural gas prices over the past year have sparked a willingness to invest in three dimensional seismic surveys throughout the Sacramento region.⁴¹ In one published report, Tri-Valley Oil & Gas recently began drilling north of the town of Tracy in what has been referred to as “the biggest hunt for natural gas in 36 years.”⁴²

The staff’s outlook for California production during the forecast period is positive after initial declines in 1999. After reaching a low of 257 BCF in 1999, in-state production is expected to increase by 2 percent per year to 388 BCF in 2019. The forecast does not account for the newly available Elk Hills supply, as the sale was completed after the current analysis. Even though the influence of Elk Hills is not reflected in the present analysis, the forecast does consider Northern California activity noted above, predicting that regional production will rebound

from its decline as these new developments become operational. After falling to 61 BCF in 1999, Northern California production is expected to increase steadily, reaching 142 BCF by 2019.

CALIFORNIA END-USE NATURAL GAS PRICE FORECAST

The staff used the NARG model-generated California border price as a starting point to complete the end-use forecast. The staff calculated border prices for core and noncore customers. Core customers include residential, commercial and small industrial. Noncore customers are large industrial, TEOR and electric generation. Appropriate interstate and intrastate charges were added to

border prices to determine end use prices for each customer class. Details of this methodology are specified in Section III of the *Natural Gas Market Outlook*.

Table 5-4 shows the resulting end-use prices by customer sector and utility for 1995, 1997 and selected years of the forecast. The base case price forecast provides the most likely trajectory for natural gas prices. Shifts in supply availability, demand fluctuations and regulatory changes could cause prices to move above or below the base case levels. Although prices rose significantly between 1995 and 1997, the current forecast indicates that all market sector prices will drop substantially during the next few years. Thereafter, prices tend to increase in real terms, due to a gradual increase in commodity prices. This increase, however, will be partially offset by cross-subsidy reductions and lower costs to operate utility systems.

Table 5-4
California Base Case End-Use Price Forecast By Sector And Utility
1998 Dollars Per MCF

Utility And Year	Res	Core Com	Ind	Com	Ind	Noncore TEOR	Cogen	EG	System Avg.
PG&E									
1995	6.75	6.81	4.96	2.68	1.97	1.62	2.38	2.38	3.80
1997	7.58	7.57	4.99	3.67	2.98	2.74	2.83	2.83	4.54
2000	6.47	6.46	3.64	3.20	2.18	2.10	2.12	2.12	3.57
2005	6.03	6.03	3.66	3.30	2.35	2.31	2.30	2.30	3.52
2010	5.94	5.94	3.71	3.41	2.52	2.49	2.46	2.46	3.54
2017	5.92	5.93	3.86	3.68	2.85	2.81	2.79	2.79	3.74
SoCal Gas									
1995	7.11	6.96	6.22	2.54	2.43	2.14	2.40	2.40	4.53
1997	7.37	5.52	4.53	3.26	3.25	3.03	3.05	3.05	4.70
2000	6.28	4.47	3.49	2.41	2.40	2.42	2.12	2.12	3.66
2005	6.21	4.49	3.58	2.67	2.67	2.69	2.38	2.38	3.75
2010	6.14	4.53	3.68	2.87	2.86	2.90	2.59	2.59	3.82
2017	6.23	4.73	3.94	3.21	3.20	3.23	2.94	2.94	4.02
SDG&E									
1995	6.85	6.72	5.65	2.88	2.91	n/a	2.32	2.32	4.26
1997	7.31	6.57	5.02	3.53	3.53	n/a	3.26	3.26	4.85
2000	6.63	5.90	4.37	2.76	2.76	n/a	2.54	2.54	4.14
2005	6.54	5.86	4.44	2.98	2.98	n/a	2.75	2.75	4.02
2010	6.36	5.72	4.44	3.13	3.13	n/a	2.91	2.91	4.00
2017	6.29	5.71	4.58	3.41	3.41	n/a	3.22	3.22	4.15

Notes:

1995 prices are historical values.

1997 prices are based on partial 1997 supply and price data.
This forecast was adopted March 18, 1998 by the Energy Commission.

Source: Commission staff report, *Natural Gas Market Outlook*, June 1998.

The Commission's price and supply availability analysis addresses long-term trends in the natural gas market. Hence, these projections do not reflect actual conditions as envisioned in today's market. Short-term market fundamentals induce price volatility which is not incorporated in this analysis. Seasonal gas price trends will be affected by a combination of parameters such as level of storage, weather patterns and demand conditions. For example, due to short-term market conditions, natural gas commodity prices throughout North America rose to high levels as a result of increased natural gas demand during the winter of 1996-97 and remained high during most of 1997. Furthermore, while natural gas production capability was more than adequate to meet demand, the ability to get production into the pipeline in major supply regions was restricted by existing capacity to gather and process the gas for delivery into the pipeline. This condition resulted in less supply competing for market share and, therefore, sustained higher prices during the past year.

Following a warm winter, natural gas prices in 1998 were lower than 1997 prices because a decreased amount of gas was needed to refill storage facilities for the next winter. In the near future, as new supplies -- such as from the offshore Gulf production region -- become available, competition to sell natural gas could drive prices even lower.

In this forecast, end-use prices generally decline through 2005 (depending on the utility and market sector considered), and then are expected to rise in real terms. Commodity costs will show small annual increases of about three cents per million Btu. New technologies to explore, find, develop and produce natural gas will help to keep the commodity prices from rising at a higher rate. Current CPUC policies to reduce end-use price subsidies and provide for more efficient utility operations will partially offset commodity price increases.

INTEGRATED MARKET ANALYSIS

While scenario planning is one tool to incorporate uncertainty into assessments of alternative future market conditions, the staff approached the issue of uncertainty differently in this *Fuels Report*. Using a combination of critical parameters, the staff constructed two integrated cases which examine long-term market conditions. Two important factors distinguish integrated cases from scenarios. First, scenarios assemble "worlds" where the interaction of the participants lead to various outcomes. Integrated cases take a more restrictive view and answer the question "What if a combination of events simulated by critical modeling parameters occurred simultaneously?" Second, in scenarios, the view of the world determines the model input values. In integrated cases, the analyst selects the critical parameters.

A review of historical natural gas prices indicates that during the late 1970s and early 1980s, natural gas prices climbed to record highs. By the mid- to late-1980s, deregulation swept the natural gas industry and competition forced lower prices. In the 1990s, energy financial markets rose to prominence. Instruments such as futures and forward contracts, options, and swaps are now commonplace in energy markets. Market uncertainty sustains the need for these financial tools.

To quantify the full range of the natural gas price forecast, the staff constructed two specific integrated cases: the **Low Price** case and the **High Price** case using three critical uncertainty parameters -- noncore natural gas demand, supply resources development and technology advances. Rather than being forecasts of the future, these cases represent bounds for natural gas supply and price under various market constraints.

High and Low Price Case Assumptions

The high price case characterizes an environment where natural gas use is higher than in the base case. In many jurisdictions, natural gas use increases as a result of air quality requirements which specifically restrict "oil burn," and reduce "coal burn." Many electricity generators, seeking a cleaner-burning fuel, switch to natural gas for both existing facilities and new additions. Furthermore, decreased technology advances

lead to lower than expected natural gas resource additions. Producers adjust their operations to keep up with demand. The total energy demand is stable, but natural gas gains significant market share as a result of policy guidelines.

The low price case reflects rapid innovations in finding and developing natural gas reserves to record levels. Technology advancements increase resource availability and decrease the time required between discovery and actual production. High efficiency gas-fired generation technologies and a competitive electricity market reduce gas demand for electric generation. Efficiency innovations at the burner tip (conservation and demand-side management) diminish growth in energy usage. Overall energy demand rises slowly. Inter- and intra-fuel competition are strong throughout the planning horizon with natural gas losing market share to competing fuels.

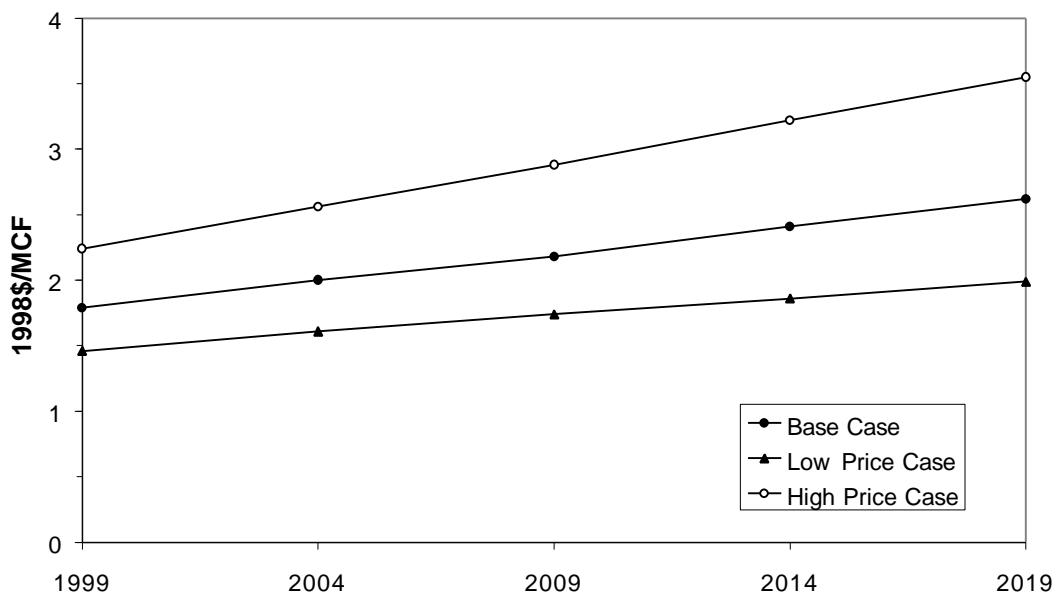
In the high price case, higher noncore demand and decreased supply availability push lower 48 wellhead prices up throughout the forecast period. By 2019, prices are 89 cents higher per MCF than base case. Figure 5-3 graphically illustrates the wellhead prices for the three cases. California border prices, shown in Table 5-5, exhibit similar behavior to that described above.

In the low price case, decreased noncore demand and greater supply availability depress lower 48 wellhead prices throughout the forecast period. By 2019, prices are 50 cents per MCF lower than the base case.

For a full discussion of the high and low price forecasts, refer to the *Natural Gas Market Outlook*, pages 63-69.

Results of Integrated Market Analysis

Figure 5-3
Base Case and Sensitivities Comparison
U.S. Lower 48 Wellhead Prices



Source: Commission staff report, *Natural Gas Market Outlook*, June 1998.

Table 5-5
Comparison of California Border (Citygate) Prices
 Base Case with High and Low Prices
 1998 Dollars Per MCF

Case	1999	2004	2009	2014	2019
Base Case	1.79	2.00	2.15	2.41	2.62
Low Price	1.46	1.61	1.74	1.86	1.99
High Price	2.24	2.56	2.88	3.22	3.55

Source: Commission staff report, *Natural Gas Market Outlook*, June 1998.

MARKET FUNDAMENTALS

Changing market conditions will continue to impact market fundamentals. These market conditions include resource (supply) availability and costs, transportation pipeline costs and capacities, demand for natural gas and economics of fuel switching options, and technology advances on both supply and demand side of markets. Although the natural gas supply and price forecast is based on a “most likely” perspective of market expectations, many uncertainties surround the natural gas marketplace. Recognizing uncertainties in the future natural gas market is essential to understanding market performance and making informed business and policy decisions for the future.

To address uncertainty, the staff created several sensitivity cases to test the bounds of the supply, demand and price of natural gas over the forecast. The sensitivity cases constructed in this analysis address the power generation market, resource availability, technology advances, overall demand and market structural changes. Each sensitivity case modifies the base case by changing a key variable to study the impact of that variable on the price and supply of natural gas.

Power Generation Market

The demand for natural gas in the power generation market is a critical parameter from a national and statewide perspective. The projected demand for this sector could swing higher or lower than the level assumed in the base case. On a national level, the Commission simulated only higher power generation demand for natural gas, assuming that gas displaces coal in electricity generation. Depending upon assumptions about the size of the displacement, natural gas wellhead prices increase 7 cents to 45 cents per MCF by the end of the forecast period.

In California, higher and lower natural gas demand in the power generation market was considered plausible, compared to base case assumptions. This demand variation is because experts do not concur on whether electricity market restructuring will elevate or reduce in-state gas use in this market. In the high natural gas demand case, competitive electricity markets drive electric generation to cheaper sources in California. Nuclear generation facilities are retired at a faster pace than in the base case and replaced by natural gas-fired facilities. The resulting California border price increases 8 cents per MCF over the base case as supplies increase by 199 BCF by 2019.

In the reduced California demand case, natural gas use for power generation remains at its level assumed in the year 2000. Renewables, out-of-state imports and increased conservation measures accommodate increased electricity demand through the remainder of the forecast period. California border prices decrease slightly compared to the base

case, with supplies to the state decreasing by 170 BCF by 2019.

Resource Assumptions

Resource assumptions significantly impact the price and supply projections. Major supply basins include the Gulf Coast, the Rocky Mountains and Canada. Assuming a 25 percent decline in available natural gas resources, compared to the base case, results in California border prices increasing by 22 to 48 cents per MCF over the forecast horizon. On the other hand, assuming higher availability in the Gulf supply region, by an additional 100 TCF of natural gas resources in federal offshore waters, production levels increase and wellhead prices decline by 17 to 36 cents per MCF. Assuming further that about 51 TCF more gas resources become available from Canada, Canadian production increases and wellhead prices further decline. In this case, California border prices drop 7 to 15 cents below the base case.

While each of these cases exhibit slight variations in lower 48 production from the base case, wellhead price variations are much more significant. All cases generate a 45 cent price range in 1999 from the low resource assumptions to the high resource assumptions in Gulf and Canadian resources. The range increases to 89 cents per MCF by the year 2019. In percentage terms, prices in the lower resource case are 31 percent above the prices when resource levels are high, in 1999 and 49 percent higher in 2019. By comparison, the range of differences between lower 48 production levels is only 3 to 5 percent.

Technology Advances

The base case assumes that the supply-cost curves incorporate current technology status for all future resource development. Additional parameters in the model allow for assumptions on how the technology advances impact the natural gas development and production. To study the impact of these technology advances, the staff simulated a “no technology” case, assuming that drilling and exploration technologies remain at present levels. Production, in this case, declines, and prices increase compared to the base case. California border prices increase by 34 to 66 cents per MCF. With aggressive assumptions regarding cost reductions, technology costs decline

to 10 percent of current values with corresponding gas price reductions. California border prices drop by 47 to 92 cents per MCF lower than in the base case over the forecast. If technology advances result in resource development two years sooner than in the base case, lower 48 wellhead prices drop 13 to 18 cents per MCF with corresponding declines in California border prices.

Overall Demand

Energy consumption requirements for all customer groups can be affected, among other things, by building standards changes, appliance efficiencies, energy intensities and competition between fuels. The staff designed several cases to test how shifts in demand affect natural gas prices and supplies produced in the base case. Two cases test changes in total demand in the US and Canada, and two cases test changing demand assumptions for core customers.

If the US and Canada demand increases 10 percent above the base case, supplies to California increase by 226 BCF. In addition, lower 48 wellhead prices increase by 37 cents per MCF, with similar California border price behavior. If demand for natural gas declines 10 percent below base case estimates, lower 48 wellhead prices decline by 24 cents per MCF and supplies to California decrease by 274 BCF by 2019.

One core sector case assumed that natural gas demand in this sector would exceed base case assumptions for the lower 48 by 4 TCF by 2015, bringing lower 48 wellhead prices up 32 cents per MCF by 2019 with California border prices following the same direction. Higher natural gas prices also increase the level of fuel oil switching. The other core sector case assumed that natural gas demand for natural gas vehicles (NGVs) exceeds the GRI’s expectations by 1.9 TCF by 2015. As a result, lower 48 wellhead prices increase throughout the forecast, becoming 14 cents per MCF higher than the base case in 2019 with California border prices again closely tracking lower 48 prices. Lower 48 production also increases, with output surpassing the base case by 2.1 TCF by the end of the forecast.

MARKET STRUCTURAL CHANGES

The staff designed three specific cases to provide insights on the impact of modifying the pipeline assumptions in the base case. The first two cases respond to a global question about pipeline expansion and rate design. The third case reviews a specific proposal to reduce southern capacity on the El Paso system and evaluates its impact on California gas supply and price.

Impact of Alliance Pipeline Project

The Alliance project is a 1.2 BCF/D pipeline extending 1900 miles from Eastern British Columbia to the Chicago area. It would allow British Columbia gas to directly access mid-western and eastern markets in the United States for the first time. Alberta gas would also access the new link.

Compared to the base case, the Alliance Pipeline would have minimal impacts on California. Lower 48 wellhead prices would remain relatively unchanged, decreasing by about 3 cents per MCF during the forecast period. California border prices would increase slightly, approximately 2 cents per MCF in 2019. While production in the lower 48 would remain relatively unchanged, Canadian production would increase by about 200 BCF per year, with the bulk going to US markets. Thus, Canadian production would supplant other sources with minimal price impacts.

Rolled-in and Incremental Transportation Rates

The question of rolled-in versus incremental rate treatment for pipeline expansions was a major ratemaking issue addressed during the mid-1990s. A “rolled-in” rate means that the cost of the capacity addition is charged to all flows old and new, while an “incremental” rate means that the entire cost of the expansion is borne by the new flows. The FERC developed a straightforward procedure to approve pipeline expansion projects while reducing the regulatory burden on all parties. Current FERC

policy allows interstate pipeline companies to roll in expansion costs as long as the post-expansion transmission rate is not more than 5 percent above pre-expansion rates. Otherwise, incremental rate treatment is adopted, creating a two-tiered set of rates for pre-expansion and incremental supply customers.

This case assumes that all pipeline expansions meet the “5 percent” rule. Any pipeline corridor that requires expansion incurs no additional transportation costs, regardless of how much capacity is needed.

Generally, the new and low cost supply regions benefit significantly in this sensitivity. Rocky Mountain supplies to California increase by about 240 BCF per year while Southwest and Canadian production both decline by about 100 BCF. Lower transportation costs from the Rocky Mountains reduce delivered prices at the California border by 19 cents per MCF. Canadian and Southwest prices also drop, 10 to 13 cents per MCF by 2019. Overall prices at the California border increase by approximately five cents per MCF in the early periods of the forecast but reverse that direction and drop five cents per MCF in 2019.

Reduction of Pipeline Capacity Available to California on the Southern El Paso System

This case addresses a reduction in demand for Permian gas at the California border resulting from increased San Juan Basin supplies to the state. In this case, all flows through the Ehrenburg delivery point to California come from the San Juan Basin via the Havasu Crossover. The El Paso line no longer flows Permian gas to California on the southern part of its system but does use it to serve markets in southern Arizona and New Mexico as well as emerging Mexican markets. In this case, supplies from the Havasu Crossover may flow east along the southern system to serve markets east of California.

Compared to the base case, lower 48 wellhead prices remain relatively unchanged through the forecast period. California border prices increase slightly, five cents per MCF by 2019. The total supply picture to California remains unchanged, with San

Juan supplies displacing Permian supplies at the California border.

THE IMPORTANCE OF NATURAL GAS MARKET CENTERS

Regulatory reforms have revolutionized the way industry markets natural gas throughout North America. Increasing competition among producers, transporters and distributors has created market centers or “hubs” where natural gas is bought and sold competitively. As further restructuring of the natural gas and electricity markets occurs, future energy markets will witness a combination of natural gas and electricity hubs, or centers, where the two forms of energy will be traded, perhaps simultaneously -- the so called convergence of energy markets.

Market hubs are useful to participants in several ways. They can improve transportation efficiency, provide load balancing flexibility, use storage more efficiently, enhance customer choice and increase producers’ ability to market their natural gas and/or electricity. Information technology can only further this goal of ensuring a more competitive and efficient market. “Real-time” information access, combined with the flexibility to purchase natural gas on short notice, has enhanced the ability of suppliers to provide gas supplies to consumers. It also has allowed marketers to serve the needs of their clientele for a competitive package of services, while maximizing their own margins.

Market hubs are significantly affected by regulatory reforms in both the natural gas and electricity markets. While wellhead natural gas supply and interstate transportation services have been largely deregulated, the regulation of natural gas markets within individual state boundaries is slowly changing. Market incentives and reforms are being introduced to enhance competition as they have been done in the interstate markets. California recently began addressing the issue of competitive natural gas markets and consumer choice programs for all consumers, including residential and small commercial customers. The electricity industry in California, by comparison, has already embarked on a dramatic

restructuring of its marketplace, breaking down the vertically integrated structure of the utility by separating the generation, transmission and distribution functions. As natural gas restructuring proceeds, the staff believes that the level of competition in markets will converge.

Development of Market Hubs and Centers

The fundamental driving forces toward restructured and competitive markets are the integration of markets and the commoditization of energy products. For example, in the old regulated era, consumers had no natural gas purchase choices. As the number of

pipelines supplying a single market increase, customers will recognize the options available to them to make alternative purchases at lower prices. At the same time, producers and pipeline companies see economic benefits by choosing when and where to sell their natural gas at the most beneficial price.

The concept of consumer choice is slowly penetrating current energy markets. Competition is increasing through restructuring or regulatory reforms. Natural gas regulators have enacted ways for producers, transporters, and consumers to exercise their choices to achieve economic benefits by removing barriers such as regulated wellhead prices, tariff limitations on pipelines, limiting access to supplies due to lack of alternative options, receipt and delivery point inflexibilities, and long-term contractual obligations.

Natural gas market hubs can simply be explained as single points or market centers where all players can sell or buy natural gas on an as-needed basis. Transactions can occur under contracts for specific time periods or through the spot market. A simple market hub conceptually consists of two or more suppliers, two or more consumers, and a storage facility, all linked by interconnecting pipelines. In practice, actual hubs need not possess all these characteristics, and the number and type of participants can vary. For example, a market center with only one producer and one storage facility, but two or more consumers, also represents a market hub. In this case, the producer has options about whether to sell gas or put it into storage, while consumers can

choose between buying the gas from the producer or taking it out of storage, depending on price.

Normally, at a market hub, marketers are also often involved in the transaction. When the marketer is involved, it is not essential that the producer knows who consumes the gas or the consumer knows who produces the gas. The marketer buys from several producers and sells to several consumers. In today's markets, marketers are represented by clearing-houses, brokers, hub managers, storage facility operators and aggregators. With options such as transportation pipeline capacity release, it is not surprising for several independent transactions to occur after natural gas is sold by a producer and before it is bought by a consumer.

Impact of Hubs or Centers on Pricing and Reliability

Market hubs clearly impact the price at which natural gas is traded. Producers have the option of selling to high bidders while consumers have the option to go to the lowest price seller. Through electronic bulletin boards and other mechanisms, information becomes more available to all market participants. This information enhances competition among sellers and buyers. Transactions can and do occur for various contract periods, such as long-term contracts and spot or daily contracts. It is probable that these market transactions in the future might even occur hourly. Today, the choices in competitive markets are available mainly to large gas consumers, such as industrial and power generation customers

and, to some extent, smaller customers through core aggregators or marketers. The number of players will increase as small and large consumers gain better access to competitive service options.

The fact that several producers are supplying the hub is sufficient for consumers to know that they will be able to procure supplies at market-clearing prices. In this instance, consumers bear the risk in deciding how much natural gas they need and for how long they will need it. On the other hand, producers have the advantage of a buyer for their natural gas if the sale price is right. Producers bear the risk in deciding how low to price their gas to ensure that there are takers for their supplies. This combination of producers and consumers weighing their individual risks ensures that natural gas is bought and sold at *market-clearing prices*, to the benefit of both parties.

The question of reliability arises when a producer or consumer has to decide on the level of risk to bear in choosing to hold off or buy gas at a specified time. The consumer's perception of future market direction will dictate the level of risk assumed by an immediate decision. In an ideal market, collection of such decisions sways the reliability factor such that consumers manage their risks by either buying gas at the available price or waiting until they can get a better price. The same is true for producers who manage their risks by either selling at the market price or holding off with the expectation that future events will raise prices to more profitable levels. These buy-sell decisions affect the market place by determining the clearing prices or spot prices at the market hubs.

Chapter 6

SYNTHETIC PETROLEUM FUEL AND FUEL CELL PROSPECTS

This chapter discusses two technology developments that may affect California fuel supply and use: conversion of remote natural gas resources into synthetic petroleum products, especially diesel fuel and fuel cell technology for transportation use. Improvements in producing synthetically derived diesel fuel from natural gas have been receiving greater attention and several companies are planning construction of pilot plants, largely outside the US, to produce the fuel. Further details of this activity, as well as the potential resource base and characteristics of the fuel itself, are discussed in this chapter. In addition, the developments in the use of fuel cells to power vehicles are presented, including fuel candidates, leading fuel cell vehicle (FCV) technologies and related infrastructure needs.

REMOTE NATURAL GAS DEVELOPMENT⁴³

Estimates of worldwide remote natural gas resources exceed 4,900 trillion cubic feet.⁴⁴ Most of these resources remain untouched for various reasons, often because of the prohibitive cost to bring the gas to market. For remote resources that have been developed, the option frequently selected involves converting the gas to Liquefied Natural Gas (LNG) for tanker transport. Many countries choose this approach as the means of “monetizing,” or capturing

the economic value, of remotely located gas supply. The construction of LNG projects continues for this purpose. These projects, however, do not play a significant role in California’s gas supply as the state has no facilities to receive and regasify LNG.

Another option pursued by some companies is to convert the remote gas into synthetic petroleum products, such as diesel fuel. This option may play a role in California’s future fuel supply picture as the diesel fuel produced is largely free of sulfur, aromatics or toxic contaminants. When blended with conventional diesel, the resulting mix can meet CARB’s stringent diesel fuel standards. Cost reductions in the conversion technology may result in many smaller gas fields being developed. These fields are where most of the remote natural gas is located.

SYNTHETIC DIESEL FUEL CHARACTERISTICS AND PRODUCTION ACTIVITY

Preliminary tests indicate that exhaust emissions from synthetic diesel fuel are from 5 to nearly 40 percent lower, depending on the pollutant, than emissions from an engine burning conventional

diesel fuel. If further commercialized, this fuel could improve the prospect of new engines meeting the national 2004 heavy duty diesel engine standards as well as improving near term diesel vehicle exhaust emissions and reducing toxic emissions.

Synthetic diesel fuel may be used without compromising fuel efficiency, increasing capital outlay, impacting transportation fuel infrastructure, or fuel costs. With synthetic diesel fuel, California refiners have the option of using the cleaner fuel to “blend up” to a cleaner product. This blending provides refiners with the dual benefits of avoiding costly refinery modifications and increasing diesel supply to meet growing demand. To be competitively priced with traditional diesel fuel, synthetic diesel produced through the gas-to-liquid process needs low cost natural gas under \$1 per million Btus.

While the Fischer-Tropsch gas-to-liquid process (named after the two discovering scientists) for accomplishing the conversion is not new, catalyst and processing technology improvements are reducing costs. Reduced conversion costs and the high cost of transporting natural gas -- four times higher than for transporting oil -- increase the appeal of remote gas development. In the next 5 to 10 years, significant amounts of cost-effective synthetic petroleum fuel may be produced from remote natural gas.

As shown in Table 6-1, several facilities for producing synthetic petroleum fuels are operating, under construction or in planning. All facilities use a form of the Fischer-Tropsch process. The South African Coal, Oil, and Gas Corporation (SASOL) began producing synthetic diesel fuel for transit

application and diesel blendstocks in 1955. In early 1998, SASOL agreed with Chevron to produce up to 20,000 barrels a day of synthetic diesel for blending with conventional diesel fuels and naphtha. The SASOL is also involved in other cooperative efforts to produce synthetic diesel fuel with Qatar General Petroleum Company and Phillips Petroleum Company and has formed an alliance with Norway.

Mossgas, a South African gas-to-liquid producer, is expanding operations and being converted from a state-owned corporation into a private, integrated oil company with exploration, storage and fuel conversion business elements. With new reserves developed from the infusion of capital, the company is expecting to have at least a 20 year future. Mossgas produces gasoline, distillates, kerosene and liquid petroleum gas from natural gas.

From 1993 through 1997, Shell Oil Company profitably produced about 12,500 barrels per day of middle distillates, petroleum waxes and naphtha at their Bintulu, Malaysia facility. In 1997, California refineries used about 25,000 tons (about 3 percent of total production) of middle distillate. Production has been suspended since late 1997 when the facility component or air separation unit exploded. Investigators believe that an improperly designed air separation unit that accumulated combustible ash from a nearby forest fire may have been the cause. The facility is under repair, and Shell expects the modified facility to resume operations by April 2000, with a 25 percent capacity boost.

It is difficult to quantify the volume of worldwide synthetic diesel fuel production that may be available in the long term. If all of the world’s remote natural

Table 6-1
Global Natural-Gas-To-Liquid Production Capacity

Company	Location	Capacity	
		Barrels/Day	Status
SASOL	Secunda, South Africa	160,000	Operating
Mossgas	Mossel Bay, South Africa	45,000	Operating
Shell	Bintulu, Malaysia	12,500	Due to be restarted in 2000
Syntroleum/Enron	Sweetwater Co. WY	8,000	Under construction
Texaco	Floating barge	2,500	Under construction
ARCO	Bellingham, WA	70 (pilot)	Under construction
Exxon	North Field, Qatar	50,000 - 100,000	Under study
SASOL/Phillips	Ras Laffan, Qatar	20,000	Under study

Source: *Hart's Gas-to-Liquid News*, November 1998. gas resources were converted to synthetic petroleum fuel, it would represent about 18 years worth of current world oil consumption. While an immense resource, it is uncertain what portion may be produced and, of that, how much might make an inroad into California's fuel supply network. The low emission qualities of synthetic diesel fuel and its initial use in California suggest that a growing market may be found here. A number of factors will eventually determine if synthetic diesel fuel will be used in California. These factors include the demand for clean fuels, industry commitments to expanded production capabilities, exhaust emission requirements, refiner behavior and capabilities, and the price of synthetic diesel.

The Commission should continue to monitor worldwide research, development, demonstration and commercialization efforts associated with synthetic diesel fuel for possible use in California.

FUEL CELLS AND VEHICLE TECHNOLOGY

Strong interest is building in the automotive community to develop FCVs. Daimler-Benz recently announced their intent to produce one hundred thousand FCVs by 2004. To move from growing interest to widespread placement, however, requires overcoming significant challenges, including market and technical barriers. A key barrier to using fuels other than gasoline and diesel in fuel cells -- such as hydrogen, methanol or natural gas -- is the absence of a well developed fueling infrastructure. A discussion of the technology, infrastructure issues and fuel options follows.

Fuel cells are electricity generating systems that convert the chemical energy of a fuel into electrical energy by combining hydrogen and oxygen in an electrochemical reaction. In fact, the FCV is a type of hybrid electric vehicle that is powered by electrochemical batteries. Many components used in electric vehicles -- i.e. electric motor, controller, etc. -- are also found on FCVs.

Some form of hydrogen is required for all FCVs being developed for near term use.⁴⁵ The most direct

method is to supply hydrogen in gaseous form. Fuels such as methanol, natural gas and gasoline can be converted into a gas consisting of hydrogen and carbon dioxide through the process of reformation. Reformation uses heat and catalysts to strip the hydrogen molecules from the carbon. The carbon is combined with oxygen (from air or water) to convert it to carbon dioxide. Reformation can take place in the vehicle, on-board, or at a fueling station off-board. This option can impact the choice of the reformer technology as well as the energy efficiency and emissions associated with the vehicle.

There are three primary reformer technologies being investigated for use in hydrogen production. They include: partial oxidation, steam reforming, and electrolysis. In reality, many of the actual systems are a combination of the various technologies. Each of these technologies could be used either on-board the vehicle or off-board at a fueling station or central plant.

INFRASTRUCTURE ISSUES AND FUEL OPTIONS

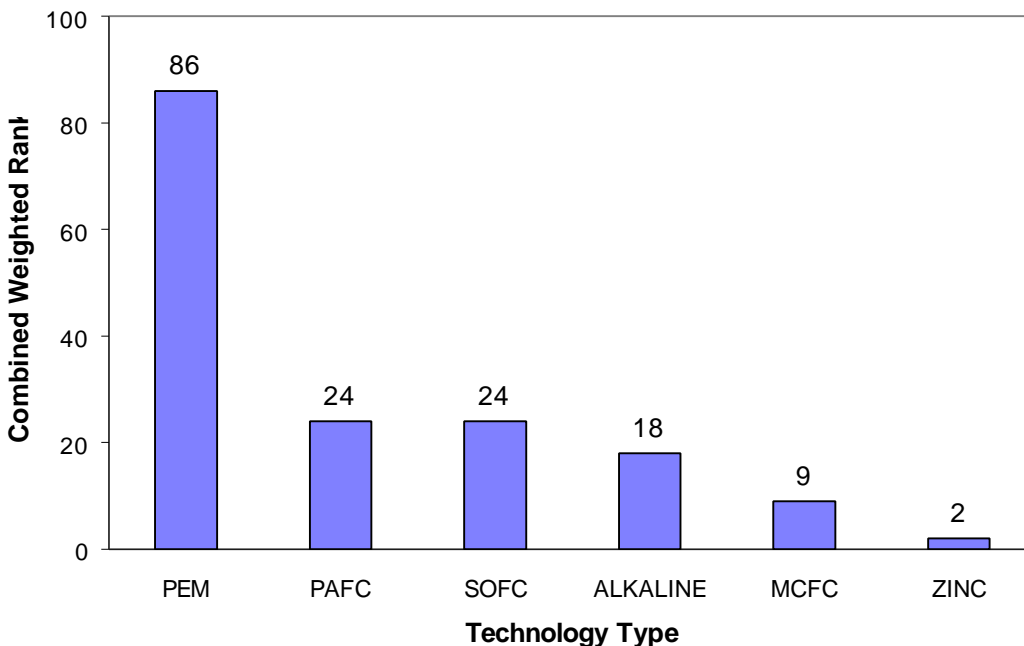
To better understand infrastructure issues associated with fueling FCVs, the staff surveyed individuals in academic institutions, government and industry who are knowledgeable on fuel cell use for transportation purposes. The survey intent was to help determine the type of technology most likely to be used, the likely candidate fuels for FCVs, and the critical infrastructure issues involved. The participants overwhelmingly identified proton exchange membrane (PEM) technology as most likely to be commercially successful by the year 2004, followed by phosphoric acid fuel cell (PAFC), sulfur oxide fuel cell (SOFC), alkaline, molten carbonate fuel cell (MCFC), and zinc. PEM technology is unique in that it converts hydrogen directly into electricity. The responses to specific technologies were weighted according to the frequency of responses as ranked in the survey and are displayed in Figure 6-1.

While the survey showed no clearly preferred fuel for fuel cells in transportation use -- gasoline, hydrogen,

methanol and natural gas receive the majority of research and development effort. Figure 6-2 displays

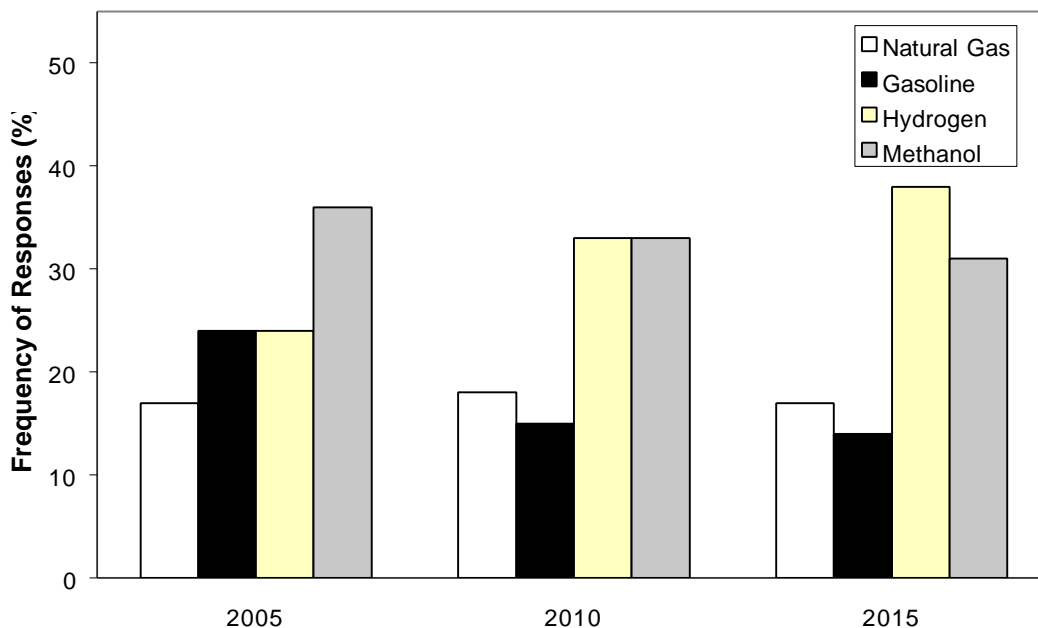
survey results for these four fuels and expectations of those likely to be used in the years shown. Methanol

Figure 6-1
Ranked Fuel Cell Technology For Use By 2004



Source: Commission staff surveys.

Figure 6-2
Fuels For Fuel Cell Powered Vehicles



Source: Commission staff surveys.

was ranked highest of the top four fuels most likely to power FCVs by 2005. Hydrogen and methanol were equally ranked for 2010. For 2015, hydrogen was the highest ranked fuel, indicating an expected shift toward widespread use of a hydrogen fueling infrastructure.

The survey specified nine infrastructure issues including production, storage, cost, safety and energy efficiency. Respondents were asked to judge whether each issue was critical, moderate or non-critical. The results indicate that hydrogen has the highest number of critical infrastructure issues, followed by methanol, natural gas and gasoline. Gasoline showed the highest number of non-critical issues, followed by natural gas, hydrogen and methanol.

The top four issues for hydrogen are storage, production, station location versus volume, and retail cost. For a variety of reasons, developing a hydrogen fueling infrastructure requires large capital investments compared to traditional fuels. For example, the Chicago Transit Authority is demonstrating three, 40-foot, fuel cell powered transit buses and has spent approximately 1.6 million additional dollars per bus for refueling infrastructure.⁴⁶ While this example is likely more expensive than development of future hydrogen fueling sites, it reveals how costly hydrogen fueling infrastructure can be. Furthermore, to directly power large numbers of FCVs with hydrogen requires the construction of a large number of fueling sites. The estimated cost to build a complete system of hydrogen production facilities, pipelines and service stations dedicated to hydrogen in the US is in the hundreds of billions of dollars.⁴⁷

Not surprisingly, the survey also indicates that retail cost is a critical issue. Hydrogen must compete with other transportation fuels, such as gasoline, natural gas and electricity.

Some studies reveal that projected hydrogen demand will be met with current supply. For the year 2010, the projected hydrogen demand for 350,000 FCVs and 300 fuel cell buses is about 55 million standard cubic feet (scf) per day.⁴⁸ This demand would be more than met with supplies estimated at 80 million scf per day.

While hydrogen and methanol producers expect that they can meet projected fuel demand for widespread

use of FCVs, many retail level issues remain. A recent report prepared for the California Air Resources Board (CARB) concluded that hydrogen is not currently feasible for use in private vehicles.⁴⁹ The major issues cited relate to storage of adequate volumes on board vehicles and the lack of available hydrogen at acceptable costs. In the interim, FCV developers will have to design and develop fuel cell stacks that can be compatible with currently available fuels.

One fuel producer, Shell UK, has announced its intent to investigate opportunities in hydrogen manufacturing and new fuel cell technologies. The company believes FCVs will enter the European and US market by 2005.⁵⁰

If FCVs were to operate on methanol, the current gasoline station infrastructure could be adapted to supply methanol, but with some modifications. Through experience establishing 46 M85 stations in California, the Commission demonstrated the feasibility of providing an alternative liquid fuel through the existing gasoline infrastructure. Although neat, or 100 percent, methanol (M100) was not provided through California's M85 retail fueling sites, all are M100 compatible.

The survey respondents selected energy efficiency, quality, safety and production as the top four weighted issues for gasoline. Energy efficiency is a concern in using gasoline for fuel cells because it is a complex hydrocarbon and reforming it into hydrogen results in reduced efficiencies. If used in FCVs, gasoline would likely require reformulation to reduce or eliminate certain compounds, such as sulfur, oxygenates and detergents that may be undesirable or harmful to the FCV reformer. If a unique formulation of gasoline is required, refinery modifications and potential supply issues would need to be addressed.

Because it is unclear which fuel or fuels will be used for FCVs, many unanswered questions remain regarding infrastructure needs. These needs include: adequate fuel production and distribution facilities; developing or expanding the number of fueling sites (e.g. methanol, natural gas, etc.); maintaining adequate fuel quality standards; and training for emergency responders and automotive mechanics.

The Commission should work closely with the US Department of Energy and its national labs, state

and local agencies (e.g. CARB and California air districts) to exchange information on fuel cell vehicle technologies and monitor their potential to change California's fuel supply requirements.

INFRASTRUCTURE NEEDS BY FUEL TYPE

Each of the four fuels discussed have unique distribution, storage, handling and dispensing characteristics which are different from one another. Vehicle manufacturers have not determined a preferred fuel at this time. In California, retail stations that could provide fuel for FCVs include: over 11,000 for gasoline, 189 for compressed natural gas, 18 for liquefied natural gas, 219 for LPG, eight for M100, and 46 for M85.⁵¹ With minor modification, some of these fueling stations could provide fuel to various FCVs for on road demonstrations.

Gasoline

Recent public announcements from A. D. Little regarding reforming gasoline for use in FCVs has brought renewed attention to this option. Gasoline formerly had not been highly regarded as a viable fuel choice. From an existing infrastructure standpoint, however, gasoline holds the greatest advantage over other potential FCV fuels. The extensive refinery, pipeline, terminal, truck distribution capability and retail network system for gasoline developed over the past century is one of the most efficient fuel product distribution systems in the world. The only major station system and component changes necessary are those required to reconfigure the fuel to assure compatibility with fuel cell systems.

Two drawbacks to using gasoline as an FCV fuel relate to gasoline quality. Gasoline for fuel cell vehicles, whether using on-board reformers or fuel station reformers, may require improvement. The constituent of gasoline most often discussed for change is the sulfur content. Presently, sulfur poisons the catalyst, the most costly part of the reformer technology. The second drawback relates to keeping a new gasoline formulation separate from

conventional gasoline. Because of the likely new gasoline formulation required by FCVs, pumps dispensing this fuel may require segregation from conventional gasoline pumps at the retail fuel station.

The research and development of both fuel station reformers and on-board reformers for gasoline continues with fuel industry and federal funding. While gasoline has the potential to be a ready fuel, given its widespread distribution and infrastructure system -- the costs, fuel economy penalty and public policy impacts of using this candidate fuel have not been thoroughly examined.

Hydrogen

Hydrogen receives significant attention by those involved in developing and commercializing fuel cells, whether for stationary or transportation uses. Hydrogen use, storage and transport technology has received substantial public and private research and development support over the past ten years for military and space applications. Many studies, with widely varying assumptions, have been prepared on the potential capital, operating and maintenance costs of a hydrogen infrastructure.

This varied and prolific research has spawned numerous scenarios. Three of those frequently considered include: hydrogen production by electrolysis, retail station fueling of hydrogen, and commercial and possible retail fuel station use of liquefied hydrogen.

No public fueling infrastructure for hydrogen exists today. Moreover, storing hydrogen on board a vehicle presents a variety of technical challenges and safety concerns not fully addressed. Alternatively, many believe a preferred design is to equip FCVs with a reformer that extracts hydrogen from hydrocarbon or alcohol fuels. Methanol, ethanol, natural gas, liquefied petroleum gas (LPG), gasoline and diesel are fuels that can be reformed to produce hydrogen.

Natural Gas

Like hydrogen, natural gas is dispensed either as a gas or liquid. Unlike hydrogen, natural gas is a blend of constituents, primarily methane. Natural

gas may be a contender for FCV as a low cost source of hydrogen. Several thousand natural gas vehicles (NGVs) are now operating in California. While this fuel is less costly than its competitors on an equivalent energy basis, sales of NGVs have been less than expected. Beyond the incremental cost of the vehicle, fueling systems are comparably expensive, over \$200,000 more each than a gasoline system, and consequently number less than 200. Additionally, the long fueling time required for gaseous fuels compared to liquid fuels limits their appeal.

Other drawbacks to using natural gas as a fuel cell fuel relate to its chemical makeup which varies significantly throughout the United States. This varied chemical makeup may affect the proper functioning of a fuel cell's reformer. In addition, the mix of gases, water vapor and particulates typically found in natural gas may also cause problems for the reformer. It is unclear to what extent the fuel makeup and its variability will impact reformer functions.

Methanol

As a liquid fuel, methanol can be incorporated into the existing gasoline infrastructure more readily than natural gas or hydrogen gas. Methanol can be used for the following:

- direct methanol fuel cells (currently under development);
- reformed and used as a feedstock to produce hydrogen either at large, centralized steam reforming plants; or
- at smaller steam reforming systems located at retail fueling locations.

California has 20 years of experience using methanol as a transportation fuel through the Commission's M85 program. Experience gained from this program includes siting and permitting of stations, tanker truck delivery to retail sites, electronic point-of-sale requirements to prevent cross-fueling of M85 into gasoline or diesel vehicles, equipment and materials compatibility problems and prevention, and the need for public education. These experiences will benefit any effort to commercialize M100 for fuel cell applications in the future.⁵²

While many of the components used in the gasoline fueling station system are compatible with fuel methanol, the materials comprising those components must be strictly evaluated on a case by case basis. For example, many of the existing gasoline storage tanks are methanol compatible, whether made of steel or fiberglass. Tank compatibility, however, must be positively determined before storing methanol. If not methanol compatible, unprotected materials may leak into fuel and render it contaminated. The type of product transfer lines at the station must also be ascertained beforehand. While black iron piping is methanol compatible in all circumstances, not all fiberglass piping is methanol compatible. Underground tanks and piping are the most difficult components to validate as methanol compatible and the most expensive to change if site excavation is required.

The costs of establishing a new, methanol compatible system at an existing gasoline fuel station are nearly identical to the costs of a gasoline system, with some increase for different materials used in the components. Using a thoroughly cleaned gasoline system with replaced or upgraded methanol compatible materials is a relatively easy and low cost approach compared to establishing a new methanol dispensing system.

Based on the Commission's experience with M85 retail refueling stations, the costs for establishing a new methanol system, excluding land costs, range from \$50,000 for an above ground tank and dispensing system to \$80,000 to \$100,000 for a new underground storage system using a 12,000 gallon storage tank and all new methanol-compatible dispensing components. These costs are comparable to dispensing and storage tank costs for a gasoline station, with the exception of material variations for the components increasing costs slightly. The costs for inspecting and cleaning an existing gasoline system and replacing the non-methanol compatible components could range from \$9,000 to as high as \$28,500 if replacement piping is required.⁵³

Because California has made a significant investment in alcohol-compatible and natural gas fueling infrastructure, Commission policy and near term planning should consider the potential needs for FCV infrastructure. Although some alternative fuel stations functioned below volume levels considered economically necessary, emerging FCV

technology may provide additional fuel demand not accounted for previously.

The Commission should continue to monitor fuel cell technology progress, infrastructure development and the potential use of FCVs.

FUEL CELL INFRASTRUCTURE REGULATION

Apart from the technical challenges of fuel processing for FCVs, the distribution, storage, and dispensing of these fuels will need to meet applicable health and safety codes. Building infrastructure involves a complex array of regulations and standards. These regulations concern fuel specifications, equipment compatibility and fuel testing, and public health and safety.

Fuel Specifications

In California, all transportation fuels must meet fuel specifications established by the CARB. These fuel specifications ensure that emission standards can be met through a combination of fuel and emission control systems on vehicles. Any fuel that enters the transportation fuels market in California will require a similar assessment.

FCVs will likely add more complexity to fuel specifications. Because hydrogen gas is not burned, it may not require extensive emission impact study; however, vehicle manufacturers may require an odorant to detect leaks, similar to the current practice of adding mercaptan to natural gas. Automobile manufacturers may need to ensure that any approved odorant will not negatively impact the fuel cell, its system or its efficiency. Other fuels may undergo greater scrutiny if emissions result through the reforming process. Some reformers may burn a small amount of the fuel, such as partial oxidation, to quickly achieve operating temperatures and thus may have measurable emissions. Gasoline-powered fuel cells may not encounter the infrastructure barriers that face other fuels but may require a different formulation as mentioned previously. FCVs using methanol reformers will likely require

chemical grade methanol (M100). Like hydrogen gas, M100 may require additives to enhance customer safety. The additives for M100 must be tested to ensure performance compatibility with fuel cell catalysts and components.

Equipment Compatibility and Testing

FCV fuel specifications will dictate requirements for dispensing and storing equipment. FCVs may require stringent fuel quality with little or no tolerance for contaminants or concentrations of constituents outside of the fuel specifications. Dispensing and storing equipment must guarantee that the fuel being dispensed will meet these specifications. Current regulations specify quality of fuel as delivered to a fueling station. They do not require testing of the fuel as it is pumped into a vehicle.

Public Health and Safety

Transportation fuels must meet rigorous public health and safety regulations. Gasoline, methanol and natural gas all have fire codes in place that give fuel providers and retailers clear guidelines on hardware and operation of fuel facilities. Safety regulations for hydrogen gas, however, may require review or, in some cases, even development. Existing codes for natural gas could serve as the basis for hydrogen fuel-related regulations.

Even so, instituting public health and safety codes is a lengthy process. Fuel regulatory codes generally do not allow much flexibility to accommodate new technologies. In addition, an array of organizations responsible for building, electrical and fire codes must approve any and all amendments. New language for amendments undergoes extensive technical review during the three year interval between publication of new codes. Furthermore, state and local governments may have their own cycle for approval which occurs after national code publication.

In California, public health and safety codes pertaining to electric vehicles required five years from the time utilities, automobile manufacturers, and government agencies began the task and the

time that the Building Standards Commission approved the code amendments. At the time of this writing, these codes have still not been adopted by the national Uniform Building Code. Although the code amendment process is lengthy, the end result should lead to more uniform treatment of hydrogen fueling facilities.

The Commission should encourage uniform regulatory standards, such as for storing and dispensing fuels, and leverage available public and private resources. Furthermore, the Commission should encourage fuel cell manufacturers and vehicle producers to set consistent standards for vehicle equipment configurations.

CONCLUSIONS

Synthetically-derived diesel fuel offers California opportunities to produce cleaner motor vehicle fuel while encouraging the use of natural gas, biomass and other non-petroleum feedstocks. Improvements in the technology to produce synthetic diesel may be forthcoming which will lower the cost (now about 10 percent higher) of the fuel over conventionally produced diesel fuels as larger scale projects and capacity grow in the near future.

FCVs will not be commercially available for several years. Because providing FCV infrastructure requires time, planning today for those potential future needs is prudent. FCVs may begin displacing some conventionally fueled internal combustion engines with near zero emission vehicles in the future.

Industry, government and academia are focusing their research and development efforts for FCVs running on gasoline, hydrogen, methanol, and natural gas. Because gasoline is economically attractive, it may ultimately be a transition fuel for FCVs and play an important role in the development

of the FCV. To some degree, the importance the CARB and US Environmental Protection Agency place on upstream emissions from fuels will influence the success of petroleum fuels used as a fuel cell feedstock.

Methanol is a candidate fuel for fuel cells, especially in California, as a medium to long-term fuel option because of its relatively low cost and the experience with its use. As has been witnessed with methanol flexible fuel vehicles, vehicle purchasers, however, must be able to see clear and significant benefits if they are to choose non-conventional fuels such as methanol.

Natural gas has a cost advantage over many competing fuels and a moderately developed distribution system; however, natural gas dispensing stations are limited and comparatively expensive to build. Furthermore, it appears that fuel cell and reformer developers have devoted less resources to natural gas compared to methanol and hydrogen.

Even though survey results showed hydrogen with the highest number of infrastructure issues, respondents identified it as the fuel most likely to be used in FCVs for year 2015. To date, hydrogen's retail infrastructure is non-existent. Because production and supply of hydrogen has been based primarily on estimates, hydrogen's biggest issues are retail distribution and fueling station storage.

Substantial economic and technical issues must be addressed if hydrogen is to be used directly for fuel cells in vehicles. Hydrogen's current price, even with vehicle efficiency gains, is likely to be comparatively high when infrastructure development costs are factored in, rendering it problematic to market as a fuel for the foreseeable future. Should issues that are generally considered secondary in nature today become more pronounced, however, -- e.g. greenhouse gas emissions, petroleum imports, etc. -- hydrogen may become more competitive with fossil fuel-derived feedstocks.

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